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UNIVERSITY OF ALBERTA

MOBILIZATION OF BITUMEN UNDER RESERVOIR CONDITIONS

BY

ANAR Y. MURJI

(C)

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE

OF MASTER OF SCIENCE

IN

PETROLEUM ENGINEERING

DEPARTMENT OF MINING, METALLURGICAL AND PETROLEUM

ENGINEERING

EDMONTON, ALBERTA

SPRING, 1991

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To My Parents

ABSTRACT

A major problem in the in-situ recovery of bitumen in the Athabasca oil sands is that, in spite of some form of thermal stimulation, much of the in-place bitumen in the vicinity of the producers is still too viscous, being largely at the reservoir temperature. This situation is complicated further in certain parts of the McMurray formation in the Athabasca, by a high water saturation zone ("bottom water") of varying thickness and extent underlying the oil sand zone. This study examined the role of bottom water for bitumen mobilization under reservoir conditions, i.e. ambient conditions. The effect of bottom water thickness and permeability, well penetration, injection rates and injection-production strategy on bitumen recovery were examined.

A new model was designed and constructed in order to improve pack properties. This model allowed for the application of an overburden pressure, better control in the ratio of the heights of the two zones and well placement. It also reduced solvent override and channelling, thus resulting in a more efficient recovery process.

It was found that a high bottom water thickness and permeability led to excessive channelling and low recoveries. Increasing the residence time improved bitumen recovery in view of increased transverse diffusion. The effect of well penetration was found to be fairly significant. A better strategy for increasing recovery is to place the injection well away from the bottom water layer and the production well fairly close to the same. Reducing the distance between the injector and producer resulted in a slight increase in bitumen recovery. A solvent-surfactant combination for bitumen recovery showed merit.

The numerical simulator was able to predict the recovery trends for the different bottom water zone permeabilities qualitatively. Based on the simulation results it would seem that the ratio of the permeabilities of the two zones is a significant factor in bitumen recovery.

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NOMENCLATURE

Latin Symbols

A	symbolic representation of a set of thermodynamic properties
BT	breakthrough
C	macroscopic liquid-phase volumetric solvent concentration
C_s	microscopic liquid-phase volumetric solvent concentration
C*	critical transition concentration
CSI	continuous solvent injection
D	diffusivity, m^2/s [cm^2/s]
Do	liquid phase molecular diffusivity, m^2/s [cm^2/s]
Ds	solid phase molecular diffusion coefficient, m^2/s [cm^2/s]
dp	grain particle diameter, m [cm]
F	convolution Kernel
Fr	formation resistivity factor
g	acceleration due to gravity, m/s^2
h	height, m [cm]
HCPV	hydrocarbon pore volume
IFT	interfacial tension, N/m [mN/m]
I_p	injection well penetration
k	permeability, μm^2 [Darcy]
k_{aw}	bottom water zone absolute permeability to water, μm^2 [Darcy]
k_{eff}	effective permeability to water, μm^2 [Darcy]
L	lithologic factor
ℓ	length, m [cm]
M	mobility ratio
N_{Da}	Damkohler number
N_{pe}	Peclet number
n_p	particle number density
OBIP	original bitumen in place
OB	overburden
OS	oil sand
p	hydrodynamic pressure, kPa [Psi]
P_p	production well penetration
PV	pore volume

q_{in}	injection rate, m^3/s [cm^3/s]
r_p, r_o	spherical particle radius, m [cm]
$\dot{r}_p$	velocity of dissolution, m/s [cm/s]
S	liquid phase saturation
s_b	bitumen saturation, % PV
sv	solvent
s	surfactant
SOR	solvent oil (bitumen) ratio, m^3/m^3 [cm^3/cm^3]
t	time, s
$\vec{v}$	Darcy velocity, m/s [cm/s]
$\vec{u}$	mass flux, $kg/m^2.s$ [$g/cm^2.s$]
WHCR	water hydrocarbon ratio, m^3/m^3 [cm^3/cm^3]
WOR	Water oil (bitumen) ratio, m^3/m^3 [cm^3/cm^3]

Greek Symbols

α	adsorption coefficient, m/s [cm/s]
α	angle of inclination of the sand with respect to the horizontal, radians
α_s	skin factor
α_l	longitudinal parameter coefficient
α_t	transverse parameter coefficient
δ	transition layer thickness
λ	mobility
μ	viscosity, Pa.s [cP]
ϕ	porosity
ρ	density, kg/m^3 [g/ml]
σ	packing inhomogeneity factor
τ	dimensionless time of miscible displacement

Subscripts

b, o	bitumen
i, j	spatial indices
m	matrix
s	solvent
w	water

1. INTRODUCTION

Alberta has a large resource of heavy oil and oil sands bitumen, which are becoming increasingly important to Canada and North America as a whole, for two reasons. One, conventional oil reserves are on a decline and thus Alberta's oil sands must fill the shortfall in energy reserves. Second, conventional oil supplies are subject to the current political climate to which the Gulf crisis (1990) bears testament. A viscosity of several million mPa.s and little or no reservoir energy makes the bitumen virtually immobile under reservoir conditions and necessitates the use of new approaches for its recovery. Another factor affecting bitumen recovery in many reservoirs, especially in the Athabasca oil sands is an underlying high water saturation zone ("bottom water") of varying thickness and extent.

Approximately seven percent of the oil sands are at a shallow depth such that they can be mined, while in-situ methods have to be used for the rest. Thermal recovery methods work best because heat drastically reduces bitumen viscosity making it more mobile. In fact, there are several major projects in operation that utilize one or a combination of thermal methods, for example cyclic steam stimulation and steamflooding. However, thermal methods have their own problems, including: poor injectivity which may make the injection pressures unacceptably high; maintenance of interwell communication between the producer and injector; tar blocking which occurs when bitumen moves to the cooler regions and seals the path, creating a zone of zero permeability; and last but not least, the presence of bottom water.

Fracturing the formation is one way of improving injectivity; however, it is difficult to predict the orientation and propagation of the fracture because of the uncertainty in the rock properties and composition. Another problem is keeping the fracture propped or otherwise, open, since the formation tends to expand with the heat, closing the fracture.

To enhance interwell communication, surfactants, caustic, ozone and various solvents have been used under cold conditions and show potential. Bottom water can be detrimental by serving as a source of channelling or beneficial by providing an initial injection path. An example of the latter type is the Peace River project in which Shell is successfully utilizing the bottom water layer for bitumen recovery.

Previous researchers have found solvents and solvent/surfactant combinations to be successful in mobilizing bitumen under reservoir conditions, in reservoirs with bottom water, but it is important to realize that any strategy that is used would have to be tailored for the location under consideration, since the compositions and thicknesses of both the bottom water and oil sand zones differ from location to location, and the factors affecting recovery would be different. This research addresses the problem of bitumen mobilization under reservoir, i.e. cold conditions. Two situations are considered in this research: one, where the in-place bitumen is mobilized by means of a solvent in the absence of any initial channel. In the second instance, an existing bottom water path is utilized for bitumen mobilization by means of solvent and solvent/surfactant combinations. The effect of variables such as bottom water permeability, injection strategies, etc., on bitumen recovery is investigated.

The objective of this research was to investigate the mobilization of bitumen under reservoir conditions, i.e. cold conditions in the presence of bottom water. This was to be accomplished through the following tasks:

1. Design a new model that allows for the application of overburden pressure and better control and flexibility in packing different layers.

2. Study the role of bottom water for bitumen mobilization by considering situations with and without bottom water.

3. Investigate the parameters that affect bitumen recovery in the presence of bottom water. These include:
   a) Bottom water thickness;
   b) Bottom water permeability;
   c) Injection rate;
   d) Well interval and penetration.

4. Study various approaches to minimize the consumption of injected material.

5. Conduct numerical simulations of bitumen production in the presence of bottom water.

The large heavy oil and oil sands deposits of Alberta are important energy sources for the future. However, it is considerably more costly to develop these resources compared to conventional oil, and thus innovative techniques must be developed for the economical exploitation of these resources. This literature review highlights some of the problems in hydrocarbon recovery from these resources as well as the experimental and field studies undertaken in their development, with the focus on the Athabasca oil sands.

3.1 The Resource

Of the four main designated areas of oil sands in Alberta, the Athabasca deposit is the largest and contains approximately 151 billion cubic meters of bitumen [1,2]. The bitumen is extremely viscous and is virtually immobile at reservoir conditions. Also, due to the shallowness of the deposit and limited reservoir energy, application of heat and pressure is necessary for bitumen recovery. The overburden thickness ranges from zero to 700 meters and is largely composed of unconsolidated and/or permeable layers, which place limitations on the choice of recovery methods in many areas of the deposits[3, 4].

3.2 Reservoir Properties

The geological characteristics and fluid properties of the oil sands are extremely variable. Formation thickness, mineral content, grain size, bitumen saturation and wettability vary within the deposit. The presence of natural geological conditions, such as high water saturation zones underlying (or overlying) the bitumen zones, and a high degree of vertical and lateral stratification affect recovery mechanisms and predictions. As a result, no one recovery technique is likely to be successful, rather, a unique concept would have to be formulated for the particular reservoir and geological conditions.

3.3 Recovery Concepts

Approximately seven percent of the oil sands reserves can be exploited by surface mining techniques, the rest have to be developed by in situ methods. An important factor in the in-situ recovery of bitumen from oil sands is viscosity reduction, since viscosity determines the mobility. The most effective method of reducing viscosity is through the application of heat because bitumen undergoes a steep reduction in viscosity with a temperature increase. Another method of reducing bitumen viscosity is through dilution by a solvent. The application of heat for viscosity reduction has resulted in the evolution of thermal in situ recovery techniques such as cyclic steam stimulation, steamflooding and fireflooding.

3.4 Problems in In Situ Recovery

Thermal in situ recovery methods are widely used. However, there are certain production problems associated with the same due to the reservoir rock and fluid characteristics [3,5]. First, because of the high bitumen saturation and viscosity and irreducible water saturation, fluid injectivity of the formations is very low, and requires an initial communication path between the injector and the producer. One method of achieving this is by horizontal hydraulic fracturing; however, fracture orientation depends on the relative magnitudes of horizontal and vertical stresses in the formation and is difficult to control.

Second, it is difficult to keep the communication path open due to blockage by the mobilized bitumen, and increase in the viscosity of the mobilized bitumen in the cooler parts of the formation. If the oil sands formations are shallow, it may not be possible to apply an adequate injection pressure. A third recovery problem is the presence of high water saturation zones in the formation which result in injection fluid loss. Under favourable conditions, however, these high water saturation zones may be beneficial in providing initial injectivity and also for providing a flow path for the mobilized bitumen.

3.5 Maintaining Interwell Communication

Much work has been done in the laboratory and the field on the creation and maintenance of interwell communication. It has been found that it is difficult to maintain communication with injection pressures below the fracture pressure. One of the methods suggested for maintaining communication at a lower pressure requires initial emulsification at reservoir conditions followed by heating of the communication path such that the bitumen entering the path would be emulsified.

Redford and Cotsworth [3,5] found that emulsifying agents such as a combination of an alkali and a nonionic surfactant, were successful in preventing formation plugging, and a low pressure process could be developed on the basis of a hot communication path through the oil sand. Laboratory studies showed that ozone readily reacts with bitumen at formation temperature to form partly water-soluble surface-active agents, which aided in the subsequent removal of bitumen at formation temperature around the fracture path.

3.6 Solvent Enhanced Communication

The use of solvents forms the basis of a wide range of enhanced oil recovery methods[6] and is a possible method of creating and enhancing interwell communication in the oil sands. In solvent displacement of bitumen, the objective is to reduce bitumen viscosity through dilution, thus increasing its mobility[7,8]. Pirela and Marcano[9] studied the rheological behaviour of mixtures of solvents and Venezuelan heavy crude oils in various proportions, at several temperatures. They found that the low viscosity of the mixtures, and the ease with which the solvent could be reclaimed made it a viable alternative to heat in the recovery and transportation of heavy oil.

The use of solvents in any in situ method is likely to be expensive, and it is therefore important to use the smallest possible amount. Also it has been found that the improper

choice of a solvent can lead to asphaltene precipitation. Various studies have been conducted using both light and heavy hydrocarbons such as naphtha, propane and carbon tetrachloride as well as gases like carbon dioxide. Raplee, Cottrell, Cottrell, and Raab[10] carried out various solubility and viscosity screening tests on different solvents. They concluded that the best solvents to use were the ones that were chemically similar in nature to the resource. For the Athabasca bitumen they found Suncor coker naphtha to be the best choice.

Hernandez and Farouq Ali [11] studied the effectiveness of a number of solvents as recovery agents, in oil sand packs and found naphtha to be the best choice from a practical point of view. Their results showed that the injected solvent swept a small portion of the sand volume, however, it was adequate to create a permeable path for the injection of additional fluids. They found that bitumen recovery depended on the displacement rate, and that solvent re-circulation after the production of the initial rich effluent significantly reduced solvent requirement.

Isaacs and Green[12] experimentally evaluated the potential of injecting refinery solvent mixtures to displace bitumen along a cold fracture path. Displacement experiments, using oil sands at 10°C, were carried out to determine the relative solubility of several solvents in extracting bitumen along the initial fracture path. Since incomplete miscibility between some solvents and bitumen caused asphaltene precipitation, the solvents were ranked in terms of compatibility with bitumen on the basis of the Bichard test and the asphaltene precipitation test. Their findings suggested that solvents that were best in solubilizing bitumen were not well suited for enlarging communication paths. Efficiency was based on the ability of solvents to create a zone of low bitumen saturation along the channel, without extracting bitumen from the other oil sands region.

3.7 Miscible-Thermal Methods

Many studies have been carried out on the combined use of heat and solvents. Hernandez and Farouq Ali [11] studied the use of several solvents in conjunction with steam. They found that solvent injection before steam was effective in creating a path for subsequent steam flow. Recovery was found to be dependent on slug size. Alikhan and Farouq Ali [13] investigated the recovery of heavy oils from unconsolidated porous media. The net oil recovery was found to depend on the rate, viscosity of the oil and solvent, and the slug size.

Farouq Ali and Abad[14] found that the bitumen recovery was determined by the type of solvent, the slug size and the solvent placement. Farouq Ali and Snyder[15] studied the recovery of bitumen from Athabasca oil sand using naphtha as solvent. They concluded that oil recovery depended on the rate of displacement, the recovery being higher at lower rates. Moreover, formation plugging due to asphaltenes was found to be a problem only after a large volume of solvent had been injected.

Redford[16] investigated the effect of combined injection of carbon dioxide and hydrocarbons on the operating recovery mechanisms. He concluded that a much larger sweep efficiency was obtained when the dual additive process was used. In all studies it was found that oil recovery by solvents was a viable method, especially when used with steam or other chemicals. Also solvent injection facilitated the much needed communication between the injector and the producer in the case of oil sands.

Shu and Hartman[17] conducted a numerical study to delineate the recovery mechanism when solvents were used as steam additives. They concluded that coinjection of solvents with steam improved production during a steam slug process, while pre-injection was not helpful. Volatile solvents were found to accelerate oil recovery, while medium volatility

solvents provided the largest increase in total oil recovery. The success of the recovery process depended on the placement of the solvent in the reservoir, which in turn, was a function of solvent volatility and steam advance rate.

3.8 Bitumen Leaching

3.8.1 Dissolution

Dissolution is the initial mechanism for bitumen leaching in which the surface phenomenon of adsorption is the driving force. Absorption is an internal phenomenon by which solvent accumulates in the solid interior, resulting in an increase in solid mass. This increase is a result of internal solvent diffusion bounded by a critical concentration, C^*, which is the function of the equilibrium concentration, S_e, above which pore space is not available for expansion.

Once the local concentrations about the contact reach the critical concentration, or in other words, when the absorption rate exceeds the adsorption rate, an irreversible phase change resulting in the dissolution of bitumen takes place. Thus dissolution is governed by the Damkohler number, N_{Da}, which is the characteristic ratio of the solvent adsorption rate in the liquid phase to the solvent diffusion rate into the interior of the solid,[18] as follows.

$$N_{Da} = \frac{r_o \alpha}{D_s}, \quad \text{.....(3.1)}$$

where N_{Da} is the Damkohler Number, D_s is the solvent diffusion rate into the solid and α is the adsorption coefficient.

3.8.2 Miscible Displacement

In the absence of dissolution, the special case of constant fluid saturation constitutes the miscible displacement of an initial bitumen distribution [19,20]. Miscible displacement of oil by a solvent can be described by the convective-diffusion transport phenomenon.

3.9 Factors Affecting Miscible Displacement

3.9.1 Mobility Ratio

Mobility ratio is the most important parameter in miscible displacement and has a significant effect on the integrity of the solvent slug and volumetric sweep. Mobility ratio, is defined as the ratio of the mobility of the displacing fluid to that of the displaced fluid

$$M=\lambda_s/\lambda_o \quad \text{.....(3.2)}$$

where the mobility of fluid i, λ_i, is defined as the effective permeability of the rock to fluid i divided by its viscosity, k_i/μ_i. In the case of a viscous oil being displaced by a solvent, there will be considerable mixing as well as fingering and an effective mobility ratio can be defined which is a function of the mixture viscosity divided by the solvent viscosity. This ratio is greater than one (unfavourable). Under these conditions, the solvent front becomes unstable, and numerous solvent fingers develop and penetrate into the oil in an irregular pattern. These viscous fingers lead to earlier solvent breakthrough and lower oil recovery after breakthrough as compared to a stable displacement front [21].

3.9.2 Mixing of Fluids by Dispersion

Diffusion and dispersion in porous media are important in miscible flooding as they have a large influence on the success of the flood. Diffusion is a process whereby mixing occurs due to random motion of molecules while dispersion is additional mixing as a result of fluid movement. There are two types of dispersion; longitudinal which is in the direction of fluid flow, and transverse dispersion which is normal to the flow direction. Perkins and Johnston[22] presented a comprehensive review of the mechanisms and equations for longitudinal and transverse dispersion.

Slobod and Thomas[23] studied the effect of transverse diffusion on viscous finger development in miscible displacement at an unfavourable mobility ratio. They concluded that at a low flow rate, which provides a long residence time for the fluids to remain in

contact, transverse diffusion is sufficiently rapid to modify the numerous narrow fingers into a single slightly bulging finger. Giardano and Salter [24] used a compositional simulator to show the influence of dispersion in displacements with an unfavourable mobility ratios. They found that transverse dispersion could eliminate fingering in an unfavourable mobility ratio flood.

3.10 Solvent Screening

Solvents used for miscible flooding of viscous oils need to be screened carefully. Certain criteria that have to be met are:

i) the solvent should be completely miscible with the oil and maintain miscibility,

ii) There should not be any phase separation, since precipitated asphaltenes may cause formation plugging,

iii) the solvent should reduce the viscosity of the oil,

iv) the solvent should be recoverable, because of the cost factor or should be used in small quantities.

3.11 Surfactants as Additives

In oil sands, the viscous forces are more important then capillary forces; however, once the bitumen viscosity is reduced, capillary forces assume increasing importance. Surfactants are detergent-like materials that are introduced into a reservoir or generated in situ, primarily to reduce the interfacial tension between the hydrocarbon and the aqueous phases and improve oil recovery [25].

Surfactants have also been used as additives to steam for mobility control. Isaacs, Prowse and Rankin[26] investigated the potential for surfactant additives in increasing bitumen recovery from oil sands. They used a petroleum sulfonate of 86 wt.% purity, based on an average equivalent weight of 418. The equivalent weight distribution is based on the

molecular weight and the ratio of mono- to di- and polysulfonates They found that bitumen recovery from the oil sand test bed was substantially improved by the addition of a relatively small amount of surfactant to continuous steam injection at 250°C. Also, the use of surfactant in displacement experiments as compared to a conventional waterflood, resulted in a comparatively lower residual bitumen saturation. In the laboratory runs the surfactant losses were severe, which could have unfavourable implications in a field situation.

Heidrick et al.[27] conducted studies on the addition of a surfactant (a petroleum sulfonate) to a waterflood for bitumen recovery. They concluded that at unfavourable mobility ratios the observed flow exhibited viscous fingering but the addition of the surfactant to the water resulted in a more uniform sweep of the porous medium thus reducing the effect of viscous instabilities. Four main criteria in selecting a surfactant are:

i) low water-oil interfacial tension,

ii) compatibility with reservoir fluids,

iii) low adsorption,

iv) low cost.

For a process to work it is important to fulfill the first two conditions, whereas, the last two conditions are of economic importance. Surfactant evaluation consists of determining adsorption, interfacial tension, and oil recovery properties.

Petroleum sulfonates have been found to be useful in surfactant flooding. Raplee et al.[10] conducted a study of surfactants on different hydrocarbons. For the Athabasca oil sand, they found the petroleum sulfonate to be the best performer among the surfactants tested. Gale and Sandvick[28] undertook a laboratory study to define optimum petroleum sulfonates for use in surfactant flooding. They found that various portions of the equivalent weight distribution made different contributions to the lowering of interfacial tension, adsorption

etc. The best combination of these properties was achieved by taking a broad equivalent weight distribution.

3.12 Sampling Uncertainty in the Determination of Bitumen in the Oil Sands

The Athabasca oil sand consists of a mixture of quartz sand, clays, bitumen and water. The quartz sand forms the bulk of the material with either the bitumen or water forming the majority of the continuous phase. The variability in the crude bitumen properties from site to site, and from one sample to another makes it very difficult to get a representative sample and is one of the problems facing the development of commercial technology for oil recovery. Wallace and Kratochvil[29] carried out an analysis of bulk samples of Athabasca oil sand, and concluded that the sampling uncertainty was much greater than the analytical uncertainty in the description of its components. Thus if an average composition were required, the samples would have had to be combined, homogenized and subsampled prior to analysis.

3.13 Reservoirs with Bottom Water

As indicated previously many oil sands have a communicating underlying zone of high water saturation often called "bottom water". The presence of bottom water in any recovery process has two conflicting effects. It provides the needed injectivity for steam and serves as a transporting medium for the mobilized bitumen. On the other hand, bottom water can act as a solvent or heat sink. The magnitude of these effects is a function of the oil viscosity and density, relative thickness and permeabilities of the bottom water zone, vertical permeability, injection rate and oil saturation.

3.13.1 Experimental Studies Involving Bottom Water

Ehrlich[30] conducted hot water and steam displacement studies on Wabasca heavy oil sand utilizing a bottom water zone. These studies dealt with both communicating as well as non-communicating bottom water zones. It was found that a bottom water layer served as a source of heat propagation, and that a considerable part of the oil was recovered before override occurred. The effect of rate on recovery was not studied.

Huygen and Lowry[31] carried out a similar study with the additional investigation of the effect of steam rate on oil recovery. It was concluded that a bottom water zone provided the initial steam injectivity, and that oil recovery and steam-oil ratio were rate-sensitive. They suggested that the influence of bottom water zone and horizontal barriers were important factors.

Kaleli[32] conducted a study in which bitumen was mobilized under cold conditions using various injection schemes. A rectangular cross-section model was used to carry out the experiments in which the effect of oil thickness to bottom water thickness was also investigated. Their results showed the recovery to be strongly dependent on solvent slug size, thickness and permeability of the water zone. Among the various chemicals used - solvent, surfactant and carbon-dioxide- solvent stimulation with surfactant was found to be most promising. Up to 68 percent of the solvent and 85 percent of the bitumen-in-place were recovered. They concluded that a bottom water zone underlying a bitumen zone could be highly effective for bitumen mobilization. Based upon numerical simulation, a bitumen to bottom water layer thickness ratio of five was determined to be optimum. It was also found that a large bottom water layer led to the dissipation of the injected fluid while thin zones required a high injection pressure.

3.13.2 Numerical Studies Involving Bottom Water

Farouq Ali and Oguztoreli[18,19] carried out a theoretical investigation of the solvent leaching of oil sand. Their mathematical model was based on miscible displacement with dissolution. Three dimensionless groups were found to control the bitumen leaching process. The Peclet number governed the miscible displacement, while the Damkohler and solvent capacity numbers governed the dissolution process. Numerical simulation suggested that the efficiency of the leaching process depended on the flow rate, solvent slug size and the relative thickness of the bottom water layer.

In a numerical study to evaluate the effectiveness of steam and steam-additive processes on bitumen recovery, Singh, Malcolm and Heidrick[33] found that for a given bottom water thickness, the injection-production strategy had a significant impact on bitumen recovery. Kisman, Best and Huyer[34] studied the influence of water sand intervals on steam drive and cyclic steam stimulation in a numerical study. They found that the performance improved when the water sand interval was thin.

3.13.3 Mobility Control in Reservoirs with Bottom Water

A significant portion of the in-place oil is not recovered by the existing oil recovery methods. Part of this oil is not contacted by the displacing fluids due to reservoir heterogeneity, and the rest is trapped by capillary forces and requires the use of methods that would decrease the oil/water interfacial tension. Under such conditions, mobility control is a factor of great importance. Recovery efficiency can be improved greatly by the use of mobility control agents such as surfactants, polymers, emulsions and foam.

Islam and Farouq Ali[35] conducted a systematic review of the mobility control agents available, and studied their relative merits under various reservoir and operating conditions. Their experimental results showed that a bottom water layer has an adverse effect on

recovery. This effect is more prominent in thick bottom water zones. They also found that the ratio of the oil-to-water zone permeabilities had a greater effect than the ratio of the thicknesses. The rate dependence was not found to be significant under the conditions studied. Viscosity also played a significant role: the recovery rate decreased drastically with an increase in oil viscosity.

All of the above-mentioned mobility control agents improved oil recovery, the choice of one over the other depending on the relative oil-water zone thicknesses, permeability contrast and oil viscosity. The optimal slug size and injection strategy were also discussed, noting that it was better to inject the mobility control agent closer to the bottom water zone when the layer was relatively thinner than the oil layer.

3.14 Scaled Models

Laboratory models play an important role in gaining an understanding of the production behaviour of the reservoir, and can be useful in determining the dominant mechanisms. However, to obtain useful results that are applicable in the field it is important to scale such experiments. Scaled models can answer relevant questions such as the effect of rate, well completion, well penetration and heterogeneities. Even though scaling limitations may preclude precise simulation of field process performance, model studies are of value in establishing trends that can lead to process optimization.

The use of mathematical models in conjunction with physical models enhances the utility of the physical model for process optimization and description. Scaled laboratory models also provide a validation of the mathematical descriptions and techniques[36]. It is important to note that the scaled model by itself may not represent the correct response of the reservoir due to the uncertainty in the reservoir characteristics due to heterogeneities and sparse sampling.

3.14.1 Scaling Parameters

Scaling criteria can be derived by an inspectional or dimensional analysis. The use of the two methods in combination is often desirable since groups that may be missed in inspectional analysis due to approximations to the mathematical equations can be accounted for by dimensional analysis. On the other hand, unnecessary groups can be deleted by the use of inspectional analysis as their physical significance is clearer than in the case of dimensional analysis. Geertsma, Croes and Schwarz[37] derived scaling groups using dimensional and inspectional analysis for the the miscible displacement case under isothermal conditions. The groups are presented below.

$$\frac{\ell}{h},\ \alpha,\ \frac{\mu_s}{\mu_b},\ \frac{\rho_s}{\rho_b},\ \frac{k\tau\rho_s g}{\mu_s \ell},\ A_{\mu,\sigma},\ \frac{\tau D\phi}{L\ell^2},\ \frac{v\tau}{\ell},\ \frac{\ell}{\sqrt{k}},\ \frac{\ell\rho_s\sqrt{k}}{\tau\mu_s} \qquad \text{.....(3.3)}$$

The last two groups were found by dimensional analysis.

3.14.2 Relaxation of Basic Scaling Criteria

Satisfying all the scaling groups imposes a rather severe limitation on the design of a practical laboratory apparatus and thus it is often necessary to omit some of them. The proper choice of groups to be deleted has to be based on experimental results, i.e. a group may be deleted once it has been found to have negligible influence on a particular case. Pozzi and Blackwell [38] have presented a set of scaling criteria for laboratory size models to simulate miscible displacement for a wide range of reservoir conditions. The scaling criteria for quite a few phenomena in miscible displacement are still uncertain and as a result there may be an error due to the relaxation of the same[39].

3.15 Field Projects in the Athabasca Deposit

3.15.1 Gregoire Lake Block I

One of the earlier projects was undertaken by the Amoco Petroleum Company, who developed the COFCAW process (Combination of Forward Combustion and Waterflooding). The process was tested in the Gregoire Lake Block I Pilot [4,40,41]. Interwell communication was initiated using horizontal hydraulic fracturing. The fractures deviated when the interwell distances were large and very limited communication was achieved between the injector and the producer. Wet combustion could not be conducted and the pilot did not demonstrate the viability of the COFCAW process at commercial well spacings. Steam stimulation was also studied at the site; however, the technique was unsuccessful due to very limited production yields.

3.15.2 GLISP Pilot

Following the Phase I project, a steam test program was initiated in the Gregoire Lake area[41,42]. This resulting project which is known as the Gregoire Lake In Situ Steam Pilot, GLISP, was operated by Amoco, AOSTRA and Petro Canada. A small inverted four-spot pattern was used. Hydraulic fracturing was conducted to initiate interwell communication. Due to the in situ stress effects existing at the depths of interest, the direction of the fractures was difficult to predict. Interwell communication between the wells could not be maintained. Also the injected steam tended to move up into the lower bitumen saturation zones from where it travelled to the producer. Foam surfactant was injected with the steam in order to reduce its mobility. This project was shut down in 1984.

3.15.3 Kearl Lake Project

The Kearl Lake project is one of the largest and more successful pilots in the Athabasca region[4,43]. It is a modified steamflood in which recovery consists of developing horizontal

fractures to establish interwell communication, followed by a combination of hot water and steam injection. One of the geological features of the area under consideration is the zone of low bitumen saturation above the main zone of interest which results in steam override. Attempts have been made to utilize this low saturation zone for interwell communication. It is thought that steam override may have a commercial application based on the results of the pilot. The pilot recently passed the one million barrel production mark and is well on its way to join the other two successful pilots, the Peace River In Situ Pilot (PRISP) and the Cold Lake Project, both of which have commercial status now.

3.15.4 AOSTRA Underground Test Facility Project.

The AOSTRA Underground Test Facility (UTF) is one of the promising technological advances in the Athabasca region[4,44]. This project is a combination of mining and thermal methods which allows below fracture steaming and provides highly efficient steam use. The design consist of two vertical shafts through the oil sand zone to the limestone formation below, in which a tunnel system is excavated. Horizontal wells, in pairs, are drilled from the tunnels into the oil sand zone above. Each pair consists of a producer lying near the base of the oil sand and an injector about 5 m above the producer.

Two thermal processes are in use in the facility. The main process is the Steam Assisted Gravity Drainage Process (SAGD). Steam is injected through the upper well and flows through the depleted zone to the cold oil face, where it gives up heat to the sand and bitumen. The mobilized bitumen drains to the lower well. The steam zone spreads as the pay zone is depleted. A second process is Chevron's Heated Steam Annulus Steam Drive Process (HASDrive). The process combines features of the SAGD gravity drainage with a controlled steam drive to effectively drain the formation. Both processes have been successful and bitumen recovery has surpassed the predictions.

3.15.5 Other Projects in the Athabasca

Shell Canada Company, Atlantic Richfield, Fina Oil Company all attempted to initiate interwell communication by horizontal fracturing. In most cases, communication could not be achieved due to formation of vertical fractures or could not be maintained due to well damage and plugging up by the mobilized bitumen. An example is the Shell Peace River Project[4] where interwell communication was maintained by high temperature emulsification of the bitumen, but the pilot was not economically viable. Suncor (1969) conducted a combustion pilot in which communication was achieved and maintained below vertical fracture pressure by simultaneously injecting solvent and air. Texaco Exploration (1973-85) was able to achieve interwell communication in one of its pilots in their Fort McMurray lease when the interwell distance was reduced. A combination of steam and naphtha was used for bitumen recovery.

4. EXPERIMENTAL APPARATUS AND PROCEDURES

This chapter provides a description of the experimental apparatus, procedures and materials used for the study. Two models were used in this work. The original model - Model I was used to investigate the effect of bottom water thickness and permeability on bitumen recovery as well as the effect of interwell distance. The second model - Model II, was designed and constructed during the course of this study and was used to investigate the effect of well penetration and different injection strategies on bitumen recovery.

4.1 Experimental Apparatus

The apparatus used in the study comprised of the following major components: physical model, fluids, porous media, injection and production systems, pressure monitoring system, nitrogen cylinder for the application of an overburden pressure (Model II) and a data acquisition system. Figure 4.1 provides a schematic of the experimental apparatus. A listing of the equipment and manufacturer addresses is given in Appendix A.

4.1.1 Physical Models

Two rectangular models were employed in the present investigation. Model I was designed and constructed for a previous study by Kaleli[32], while Model II was designed during the present study and has accounted for some of the obvious problems in Model I.

Model I

Model I (Fig. 4.2) consisted of a tubular aluminium vessel with a rectangular cavity 60.8 cm long, with a lid at the top for packing in the oil sand layer. The pack (oil sand and bottom water) was 3.8 cm in width and had a depth of 6.3 cm. The vessel could be rotated for packing the different layers and for clean-up.

Two end-ports were provided for packing the bottom water layer. Entry for the wells was through the bottom of the vessel. Both the interwell distance and the well penetration could

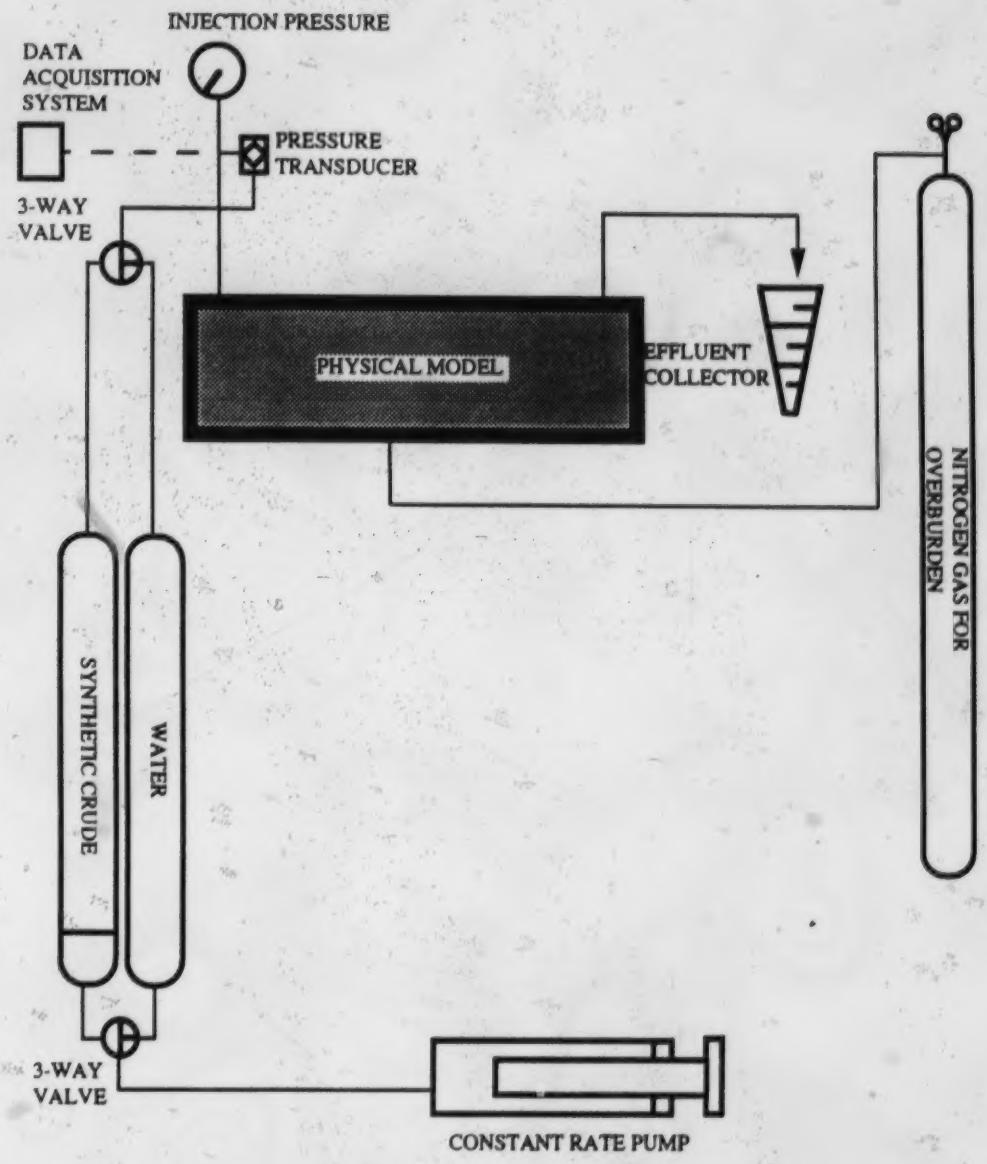
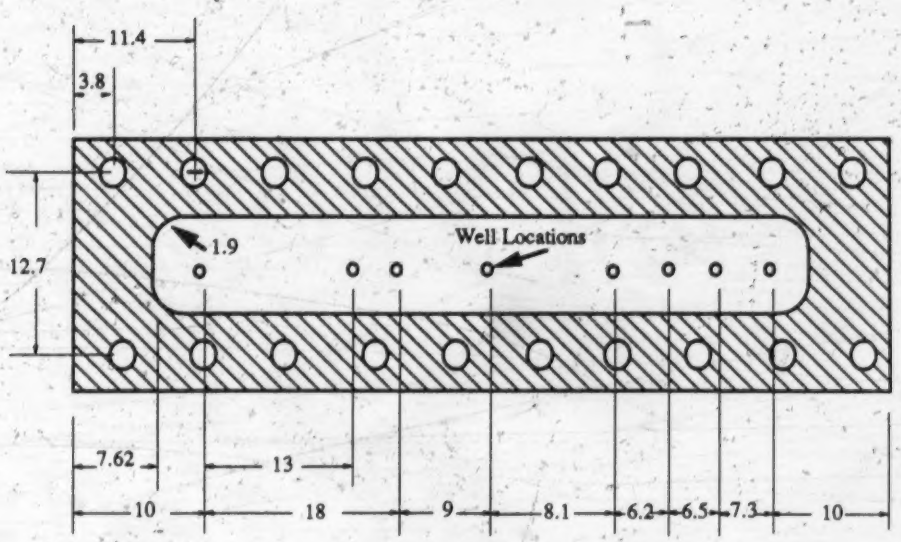
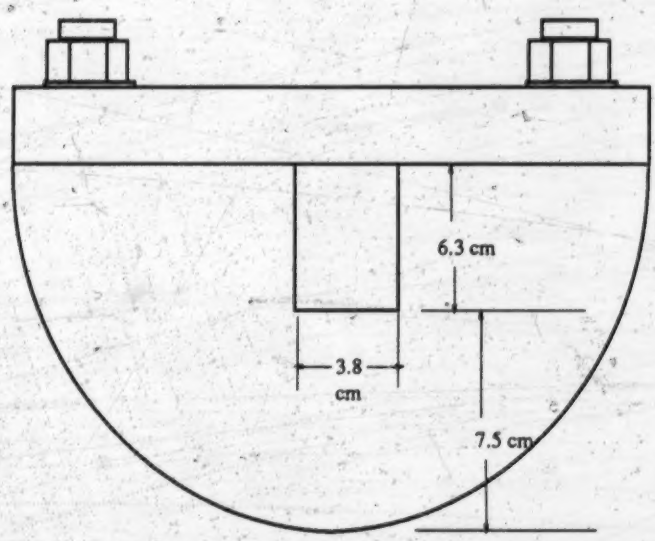


Figure 4.1: Schematic of Experimental Apparatus.



Top View (Not to scale - all lengths in cm)



End View (Not to scale - all lengths in cm)

Figure 4.2: Model I Top and End Views.

be adjusted. The well heads were made from 40 micrometre filters. The model was rotated 180 degrees for the bottom water runs. Up to eight wells could be installed in the model. A close-up view of the model is shown in Plate 4.1.

Model II

Model II (Fig. 4.3) was designed to minimize variations in the pack properties and allow better control in placing the wells and setting the exact ratio of the bottom water-to-oil sand thicknesses. An additional feature of the new model was that an overburden pressure of up to 4200 kPa could be applied to the model through a Neoprene diaphragm. An overall view of the apparatus is shown in Plate 4.2, while an inside view with the wells in place and the blank on the side is shown in Plate 4.3.

The model consisted of an aluminium block with a rectangular cavity, 90 cm in length with a width of 3.8 cm and a depth of 9 cm on a stand that allowed the rotation of the model in both the vertical and horizontal directions. Lids were provided on both sides and two packing ports at one of the ends through which the oil sand and glass beads for the bottom water could be packed. The two lids facilitated the placement of a 'blank' which was an aluminium block of the same dimensions as the bottom water layer while the oil sand was being packed. These lids facilitated packing of the oil sand from the end-port, if needed. The interwell distance could be adjusted by using a combination of the five ports available for injection and production.

Special wells of different heights were constructed to simulate different well completion intervals. These wells were made of brass and had a 40 micrometre filter at the end. Five "dummy wells" were incorporated, which could be used as plugs when the injection/production ports were not being used.

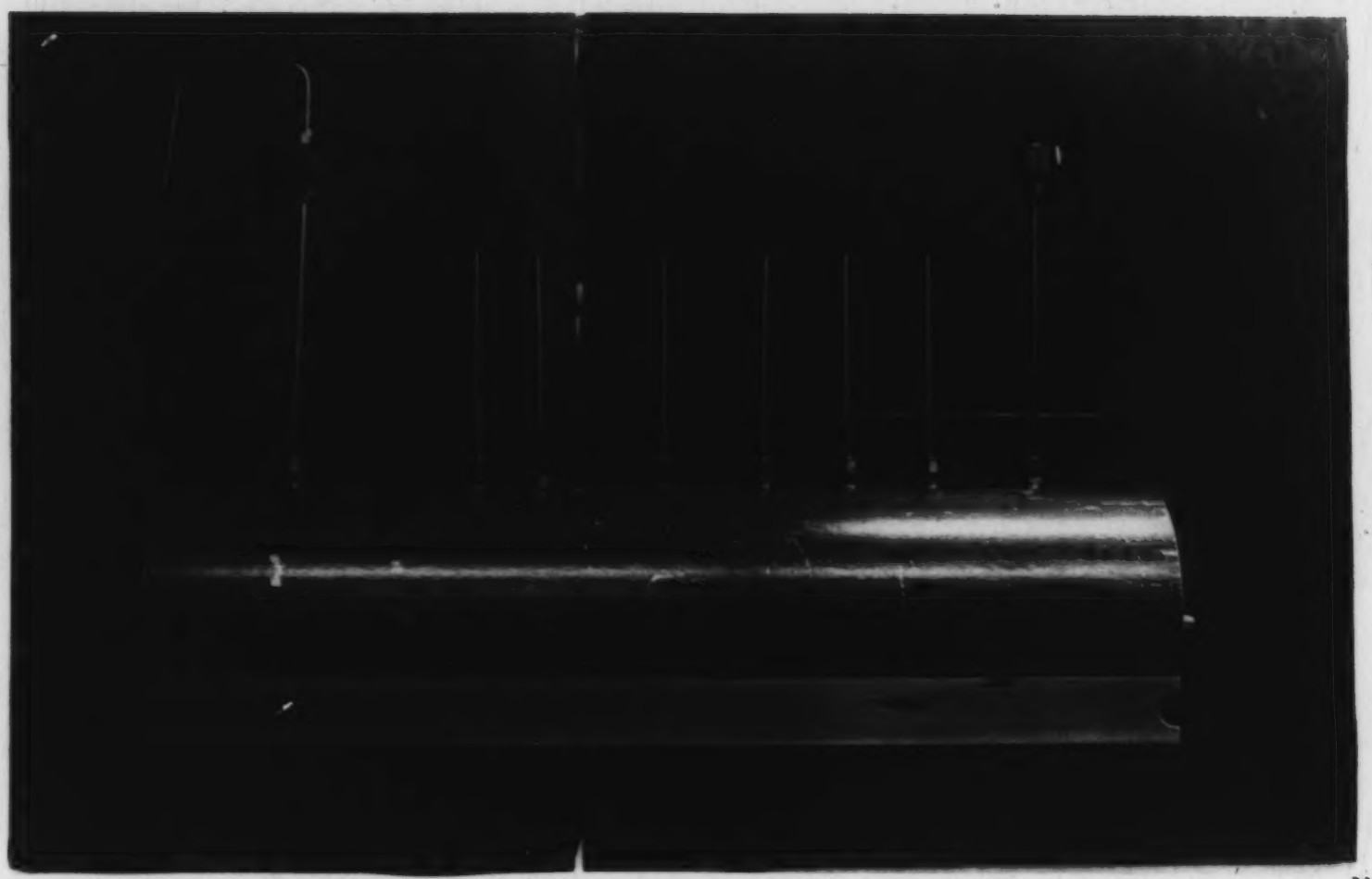
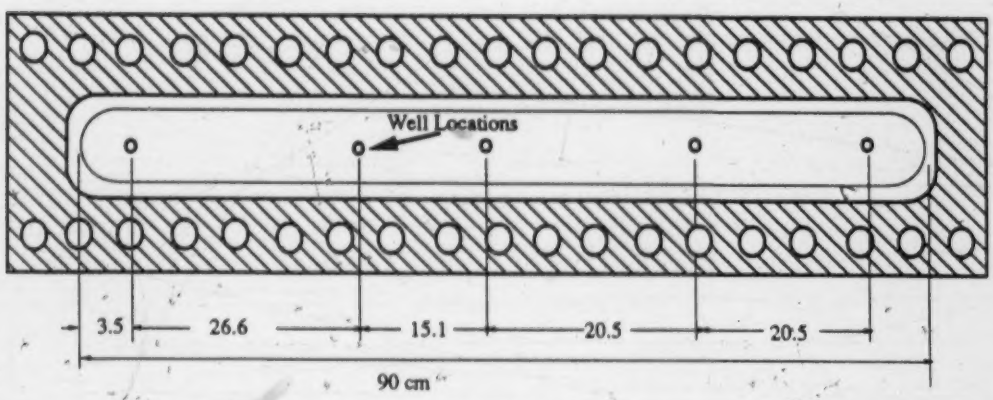
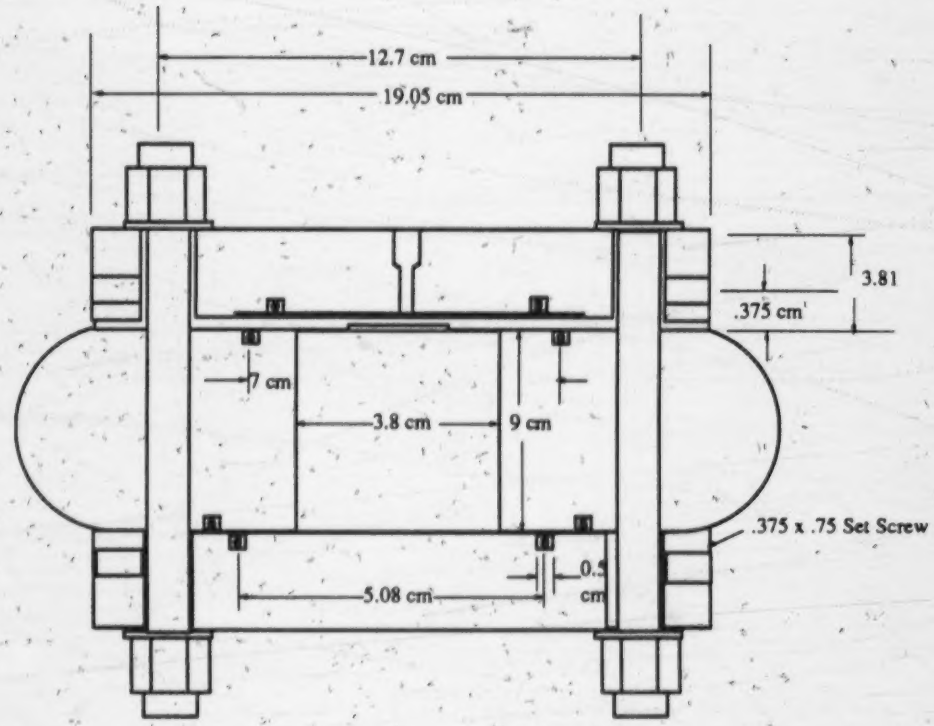


PLATE 1: Model I - Close-up View.



Top View (Not to scale - all lengths in cm)



End View (Not to scale - all lengths in cm)

Figure 4.3: Model II Top and End Views.

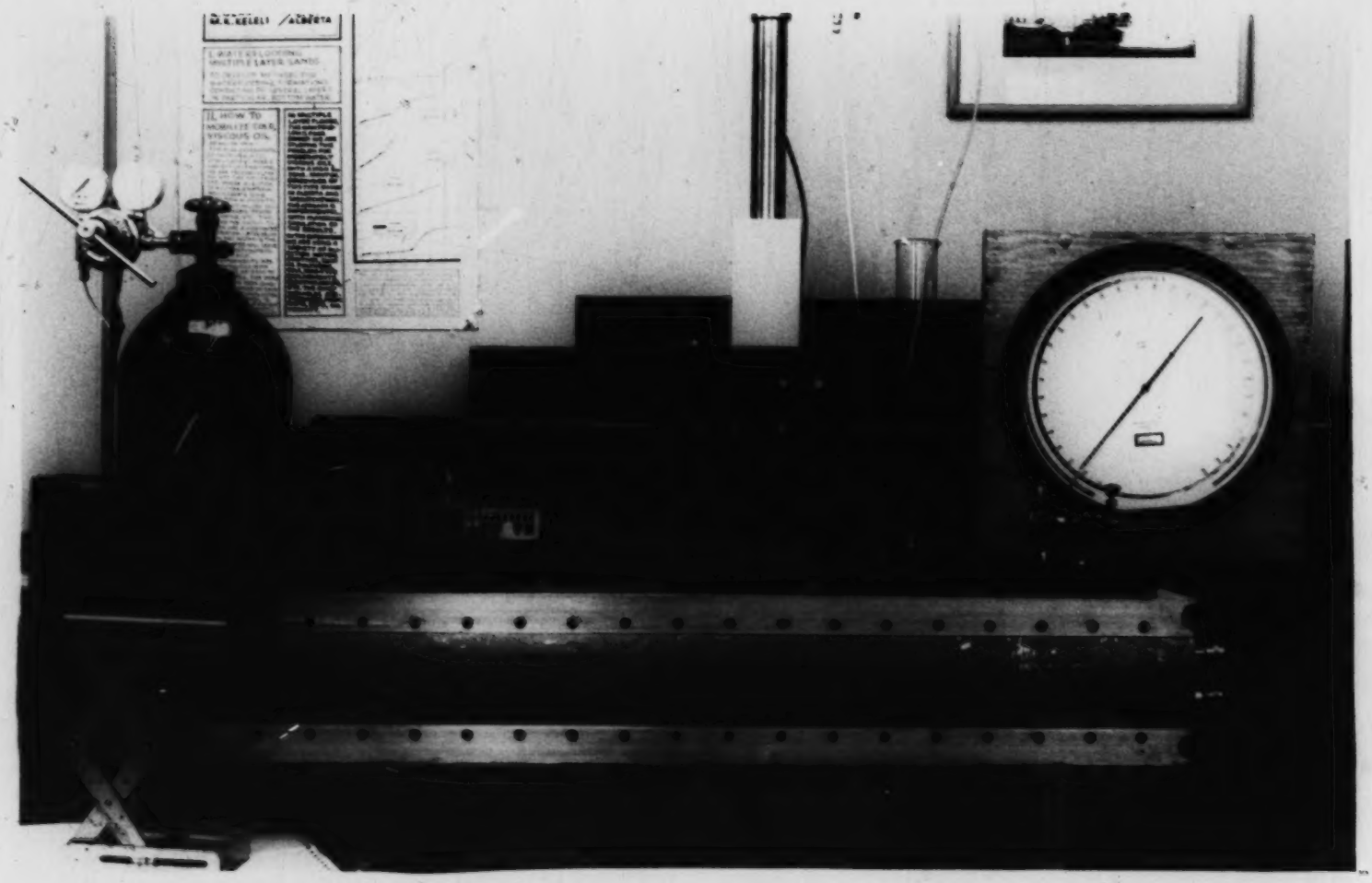


PLATE 2: Model II - Overall View of Experimental Apparatus

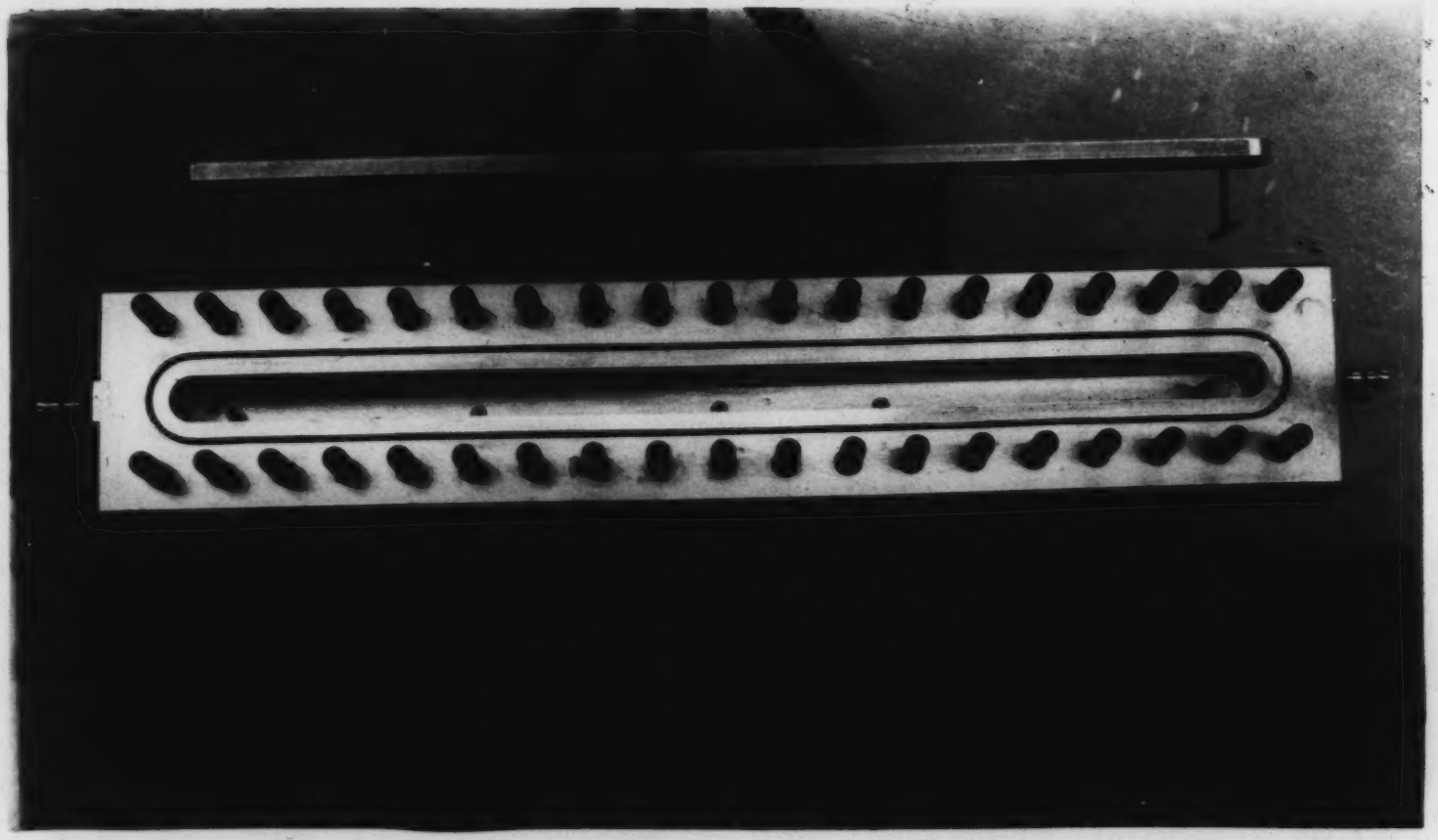


PLATE 3: Model II - Inside View with the Wells in Place and the Blank on the Side.

Two end-ports were provided at each end of the model with 40 micrometre stainless steel sintered discs to ensure uniform fluid flow distribution. These ports were used for model saturation and for conducting permeability measurements. The bottom lid had a cavity for applying the overburden pressure. There were pressure compensating set screws on both side of the lids which helped to prevent deformation of the model by transmitting the shear stress to the bolts.

4.1.2 Injection, Production and Pressure Monitoring Systems

An ISCO LC-5000 syringe pump filled with distilled water was used to displace the injected fluid from a 4000 ml cylinder into the pack. The produced fluid was collected in 50 ml centrifuge tubes. A Heise gauge and a calibrated pressure transducer provided the pressure data for each run. A data acquisition system was incorporated to automate the pressure readings.

4.1.3 Data Acquisition System

The data acquisition system consisted of an IBM compatible computer, Labtech Notebook Software, Das-8 board and an Exp-16 Multiplexer manufactured by MetraByte. Labtech Notebook is a package that is completely menu-driven which makes it easy to design a format for data acquisition - pressure and time. Data from Labtech notebook can be interfaced with Lotus 1-2-3 for post acquisition analysis, file management and graphic presentation.

4.1.4 Porous Media and Fluids

Porous Media

Athabasca oil sand obtained from the Alberta Research Council was used to pack the top layer. The bottom water layer for the bitumen mobilization studies consisted of

either 70-100 mesh, 20-40 mesh or 170-325 mesh glass beads. Properties of the components are given in Table 4.1.

Fluids

Suncor synthetic crude was used as the displacing fluid for bitumen mobilization studies. Stepanflo 80 surfactant was used in conjunction with the solvent in some runs. The physical properties of the fluids are given in Table 4.2. The simulated distillation data for the synthetic crude is shown in Figure 4.4.

Chemicals

Toluene for bitumen extraction and calcium chloride for effluent dewatering, prior to infrared spectrophotometric measurements.

4.2 Packing Procedure

4.2.1 Model I - Packing Procedure

The injection and production wells were fitted in the cleaned-out model. Well-sorted oil sand that had been stored in a cool place and excluded from air was weighed accurately and packed into the model. The packing was done manually by tamping a small amount of oil sand at constant pressure. The oil sand was packed to a pre-determined level and the vessel was then assembled. Next the model was rotated 90 degrees - i.e. kept in a vertical position - and the bottom water layer was packed using the wet packing technique. The glass beads were also weighed accurately before packing.

The pack was evacuated after the removal of water by forced air drying. Distilled water was then filled from the bottom to check the pore volume and the effective permeability to water was measured. The injection lines were connected and purged with the injection fluid.

Table 4.1 : Physical Properties of the Porous Media

Component	% (wt) in Oil Sand	Average Density g/ml*	Viscosity mPa.s *	Mesh Size
Oil sand				
Extracted sand	83 - 85	2.65	—	—
Bitumen	13.7 - 15.5	1.03	191000 **	—
Water	1 - 2.7	1	1.00	—
Bottom Water				
Glass beads	N/A	2.5	—	20-30
	N/A	2.5	—	70-100
	N/A	2.5	—	170-325

Table 4.2: Physical Properties of the Injected Fluids

Injected Fluid	Density g/ml *	Viscosity mPa.s *
Suncor Synthetic Crude	0.8665	4.6
1.0 % Surfactant Solution ***	0.9997	—
0.1% Surfactant Solution ***	0.9985	—
Water	0.9975	1.0

* At room temperature (23 °C)

** Extrapolated

*** The surfactant is Stepanflo 80, which is a 55% medium molecular wt. sodium alkyl aryl sulfonate.

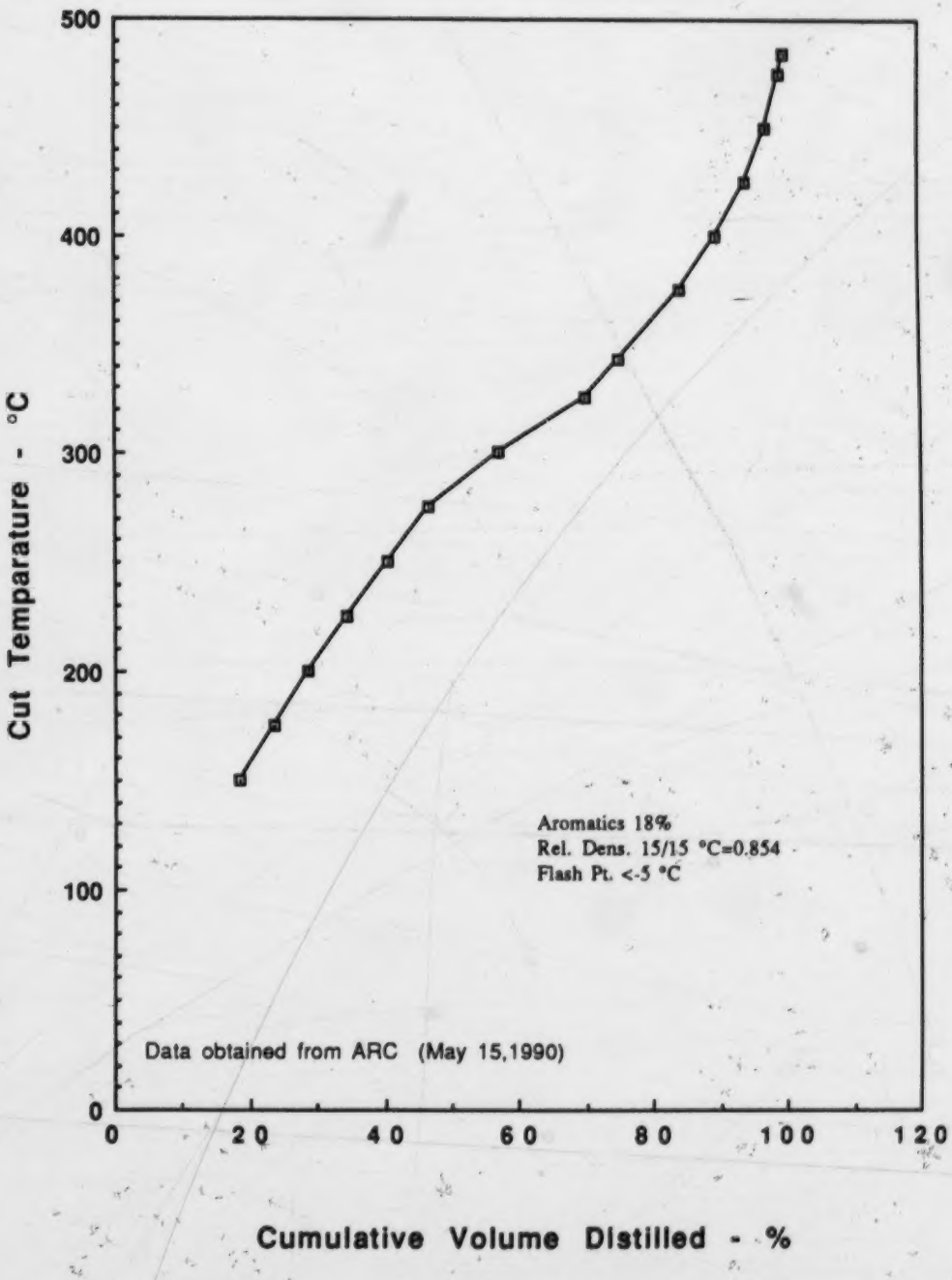


Figure 4.4: Simulated Distillation Data for the Suncor Synthetic Crude.

4.2.1 Model II - Packing Procedure

The model was assembled with the bottom water blank in place and oil sand was packed from the end-port. While the oil sand was being packed a vacuum was applied through the overburden hole to prevent the blank from being displaced by the Neoprene diaphragm. After the oil sand layer was packed the end-port was closed, the dummy injection and production wells were removed and the actual well were positioned in place (a cork borer was used to drill to the required depth of oil sand).

The bottom lid was dismantled to remove the blank and fill the cavity with wet glass beads to simulate the bottom water layer. The O-rings and Neoprene diaphragm were then placed in position and the bottom lid was reassembled. The bottom water layer was filled from the side lid instead of the end-port because the Neoprene diaphragm had a tendency to push against the cavity resulting in a loose pack with channels. The overburden pressure was applied and water was removed from the pack after which it was evacuated. Distilled water was filled from the bottom into the core and the effective permeability was measured.

4.3 Experimental Procedure

4.3.1 Continuous Solvent Injection Runs

The displacement run was started by injecting the Suncor synthetic crude at a constant rate. Effluent from the model was collected in 50 ml centrifuge tubes. The quantities of bitumen, solvent and water in each fraction were determined and the pressure was constantly monitored.

The first eight experiments for bitumen mobilization were terminated after approximately three hydrocarbon pore volumes (HCPV) of solvent had been injected or when the effluent contained virtually no bitumen. For the next five experiments approximately six HCPV's of solvent were injected. Three of these runs utilized an additional injection well to study

the effect of different injection strategies while the other two runs were baseline runs. These thirteen experiments were conducted in Model I.

A total of seven experiments were conducted in Model II. Four of these were continuous solvent injection runs, which were terminated after approximately 2.5 HCPV's of solvent had been injected.

4.3.2 Multiple-Slug Injection

The last three experiments consisted of either water or surfactant-alternating-solvent. A total of three slugs of solvent were injected. In most of the previous experiments it was found that a large percentage of bitumen was recovered during the injection of 0.5 HCPV solvent after which the rate of recovery decreased. Based on this observation a solvent slug size of 0.5 HCPV was chosen.

The water and surfactant slug size was based on an aqueous-to-hydrocarbon phase ratio of four. An upper limit of 0.5 HCPV was set on both the surfactant and water slug. Both the water and surfactant were injected from the pump. For every change of injected fluid, the lines were flushed with the injection fluid and pressurized to the core pressure, prior to resuming injection.

Surfactant Floods

The last two runs in the study were surfactant-alternating-solvent runs. The capacity of the surfactant to displace the bitumen is influenced by the interfacial tension between the aqueous system and the bitumen. The reduction in the interfacial tension depends on the nature of the surfactant and the bitumen in the reservoir. Petroleum sulfonates have been found to be efficient when used with bitumen [26,27,28], thus, Stepanflo 80, which is a petroleum sulfonate, was chosen for this study.

Interfacial tension reduction is also dependent on the composition of the bitumen and surfactant. To investigate the minimum concentration of surfactant to use in the study, a plot of interfacial tension (IFT) versus surfactant concentration was prepared using a 33 (wt)% bitumen solution in Suncor synthetic crude. The surfactant concentrations ranged from 0 to 1.0 (wt)%. The interfacial tension was determined using a DuNouy tensiometer. Concentrations used in the study were 1.0 and 0.1% and were taken at the two extreme points after the rapid decrease in the IFT.

An important property to consider in surfactant flooding is the amount of surfactant lost into the formation and also its reactivity with the reservoir fluids. For the surfactant used in the study, an attempt was made to determine how much surfactant was lost and to see if the presence of surfactant affected the absorbance readings on the Infrared (IR) spectrophotometer.

The test was done by first mixing the surfactant and bitumen solutions and then separating the two layers. The hydrocarbon layer was analyzed on the IR spectrophotometer and was compared to the control layer which had been treated in an identical manner except water was used in place of the surfactant. The aqueous layer was analyzed with the ultraviolet (UV) spectrophotometer and compared with the untreated surfactant solution.

4.3.3 Post-Run procedure

After termination of a run the model was dismantled and core samples were taken at eight fixed points to obtain the in situ final oil and water saturations. The core samples were observed for the area swept, and were extracted using the technique described for evaluating bitumen content in the oil sand. The extract consisted of a mixture of bitumen and solvent. The bitumen concentration was determined using Cragoe's method[45] which

represents changes in viscosity of liquids with changes in temperature and composition. The model was cleaned and prepared for the next run.

4.4 Analytical Methods for determining the Essential Rock and Fluid Properties

4.4.1 Bitumen Content of the Athabasca Oil Sand

The bitumen content of the Athabasca oil sand was determined for each run, as the oil sand composition can vary. Approximately 100 g of oil sand was weighed accurately into an extraction thimble. A soxhlet extraction procedure was used to determine the bitumen content which was separated from the solids by continuous refluxing with toluene.

The water distilled out by the procedure was collected in the side arm and measured. The extracted sand was dried in an oven at 100°C and weighed. The toluene in solution with the bitumen was distilled off in a Rotavapor evaporator and the weight of bitumen determined. In this way, the composition of the oil sand was determined. The post-run samples were treated in the same manner. The density of the extracted sand was determined using an analytical balance and a pycnometer.

4.4.2 Determination of Bitumen Content in the Effluent

The effluent collected in the 50 ml tubes was centrifuged to obtain the water content. The bitumen-and-solvent layer was then dewatered using a 50% (wt) calcium chloride aqueous solution. The dewatered mixture was analyzed at a wavelength of 1595 cm^{-1} using an IR spectrophotometer. The bitumen concentration in the effluent was read off the calibration curve (Figure 4.5).

4.4.3 Preparation of the Calibration Curve

Bitumen extracted from the oil sand was weighed accurately to within 0.0001 g, and mixed with the Suncor synthetic crude in different proportions to prepare standard solutions for

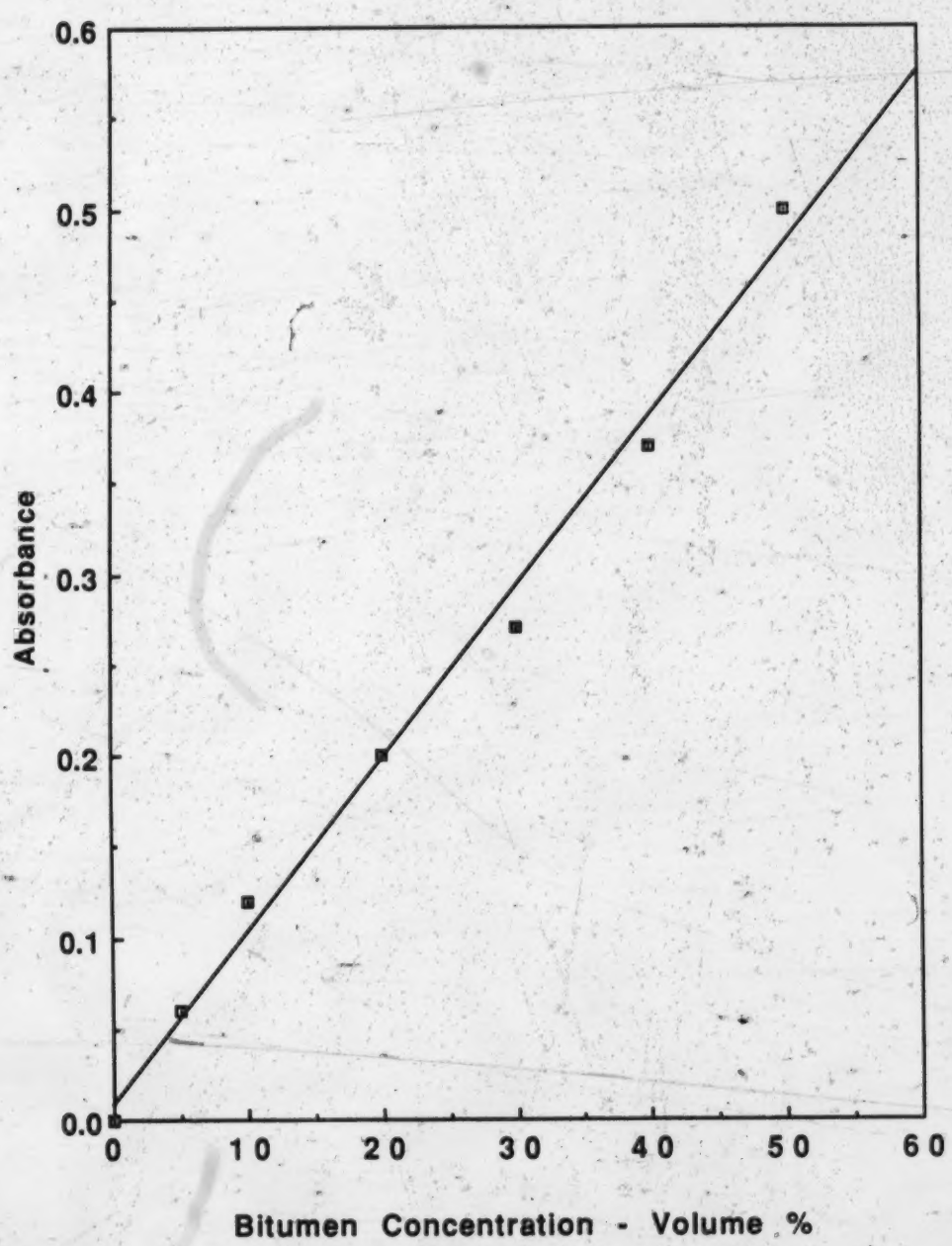


Figure 4.5: Bitumen Calibration Curve.

the concentration range 0-50% (V/V) for Infrared (IR) analysis. Absorbance at 1595 cm^{-1} was determined for each sample and plotted vs. concentration in Figure 4.5.

4.4.4 Determination of Surfactant Concentration in the Effluent

The surfactant concentration of the effluent was determined using a Bausch and Lomb Spectronic 2000 Ultraviolet spectrophotometer system. The effluent had to be filtered in order to remove traces of the organic phase before the absorbance could be determined at 222.9 nm.

4.4.5 Determination of Pore Volume

The pore volume was determined using the gravimetric method and included the bottom water layer. The volume of the apparatus was determined by filling the assembled model with water, and measuring the water content accurately with a graduated cylinder. The void space was determined by subtracting the volume of the bitumen, clean sand and water in the oil sand, and glass beads (in the case of bottom water runs) from the volume of the apparatus. The pore volume was the sum of void space, bitumen and water volumes from the oil sand.

4.4.6 Density and Viscosity Determination

The densities of the bitumen, the Suncor synthetic crude and surfactant solutions were determined on a Paar DMA 600 densitometer. The viscosities of the fluids were determined using a Brookfield cone/plate digital viscometer Model DV II. The viscosity of the bitumen as a function of temperature and solvent concentration is plotted in Figures 4.6 and 4.7, respectively.

4.4.7 Porosity and Permeability of the Glass Beads

The model was packed with glass beads using the wet packing technique. The water was removed by forcing air through the pack and evacuating the model overnight. Next,

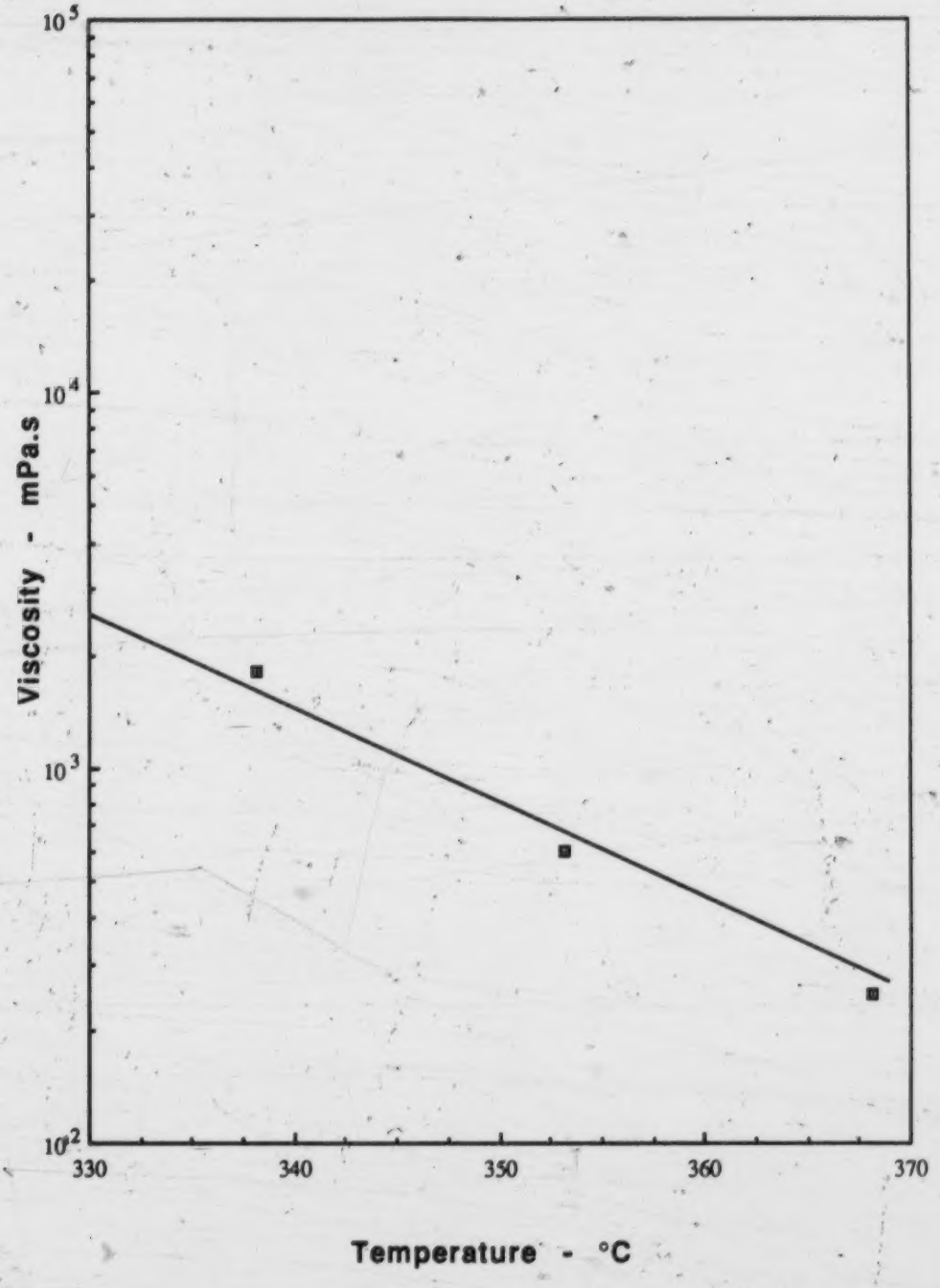


Figure 4.6: Viscosity as a Function of Temperature.

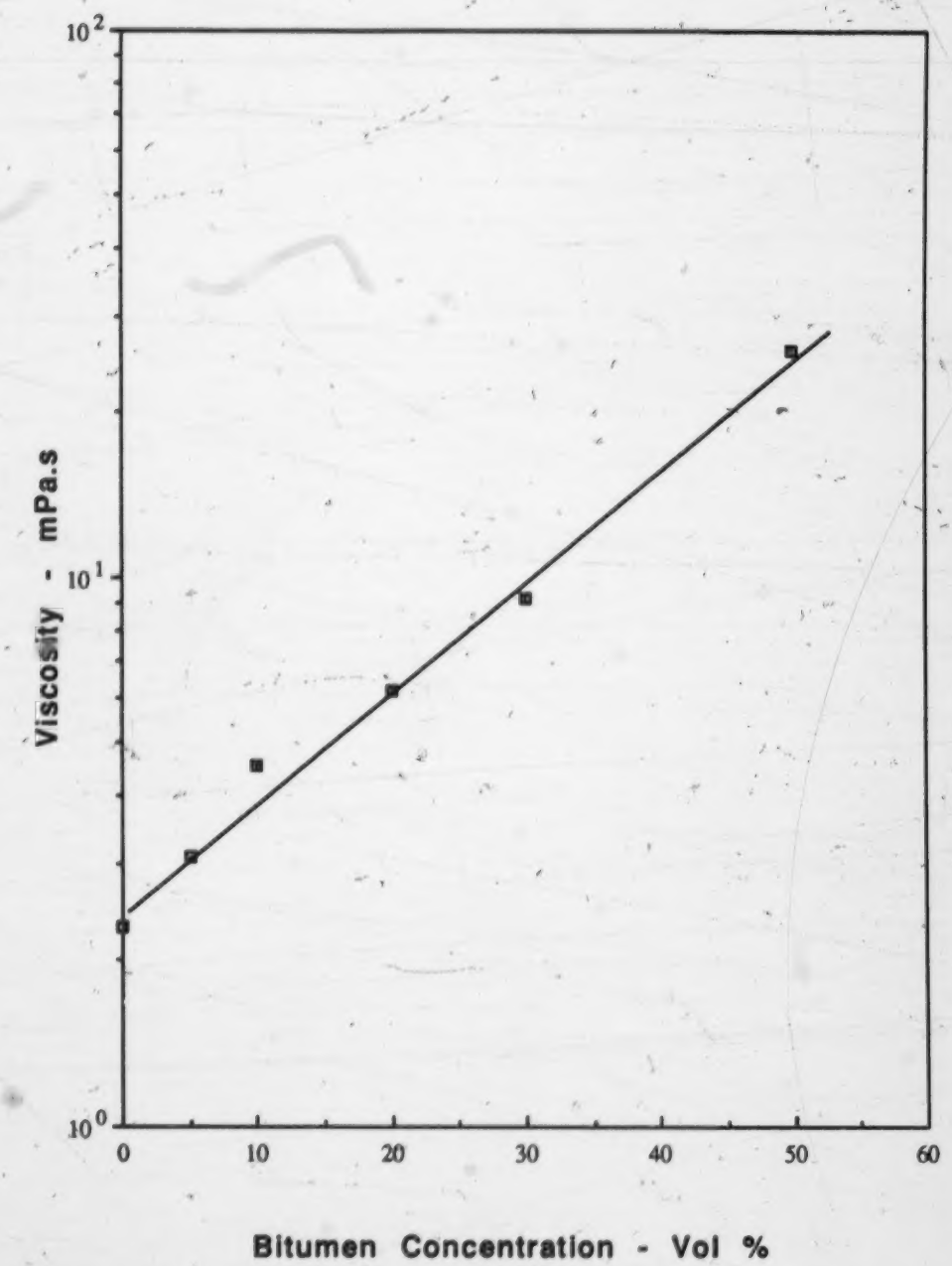


Figure 4.7: Viscosity as a Function of Bitumen Concentration.

distilled water was filled from the bottom into the pack. Volume of the glass beads was determined by dividing the weight of glass beads in the model by the average density of the beads.

The fractional porosity was determined as:

Porosity, $\emptyset$ = {[bulk volume -volume of glass beads] / bulk volume} .....(4.1)

The absolute permeability of the glass beads to water was determined by injecting water through the glass bead pack at a constant pressure and determining the production rate. Darcy's equation for linear horizontal flow was used to determine the permeability. This procedure was repeated three times to check the reproducibility of the packing procedure. Porosity for the three trials were within 3% with an average porosity of 38%, and permeability of 24 μm^2 for the 70-100 mesh beads. The absolute permeabilities for the 20-40 and 170-325 mesh beads were 200 and 2 μm^2, respectively.

4.5 Types of Experiments

Experiments for bitumen mobilization studies were conducted in three stages.

a) Solvent Displacing Bitumen in an Oil Sand Pack This phase of experimental work was mainly for testing and evaluating the capability of the apparatus and equipment. Evaluations led to the design of the improved model - Model II. These runs were also used as base runs to evaluate the effect of bottom water on bitumen recovery.

b) Solvent Displacing Bitumen in an Oil Sand Pack with Bottom Water Apart from contributing to the further evaluation of the equipment, and refining of the apparatus and operational procedures, these experiments were used to fulfill the first three tasks set out to fulfill the objective of the study. The principal variables were: oil sand-to-bottom water zone thickness ratio, bottom water zone permeability, injection/production well penetration and interwell distance.

c) Multiple-Slug Process in an Oil Sand Pack with Bottom Water At this stage of the study an attempt was made to find methods of minimizing solvent injection. This was done by alternating slugs of water or surfactant with solvent.

5. DISCUSSION OF RESULTS

5.1 Introduction

The following section describes the results of experimental studies conducted on the mobilization of bitumen under reservoir conditions. Two situations are considered. One, where the in-place bitumen is mobilized by means of a solvent, in the absence of any initial channel or flow path. In the second case, a bottom water path is employed for bitumen mobilization. The experiments were conducted on two models, viz. Model I, and the newly designed Model II, both of which were described in the experimental section. Table 5.1 indicates the model used (Model I or Model II), the process used (continuous solvent injection vs. a combination of solvent and surfactant or solvent and water), the model parameters (ϕ, k_{eff}, s_b), the experimental parameters - h_b/h_w, where h_b is the oil sand (bitumen) zone thickness and h_w is the bottom water zone thickness, injection rate, the bottom water zone absolute permeability to water, k_{aw}, etc. - and the corresponding bitumen recovery as a percentage of the original bitumen in place; OBIP.

A flow chart indicating the various parameters studied is presented in Figure 5.1. As indicated in the flow chart, six main variables were investigated. An analysis of the reproducibility of results and a comparison of the two models were also conducted.

5.1.1 Run Data

The mass weights of the porous media and the composition of the oil sands were determined and used in the calculation of the porosity and the initial bitumen saturation of the core. An effective permeability to water was also measured and used as a check on the consistency of the pack. The data collected during the run consisted of: injection pressure (gauge), cumulative solvent injected, time, and the effluent produced, which was collected in 50 ml centrifuge tubes. The effluent consisted of two layers: aqueous and hydrocarbon

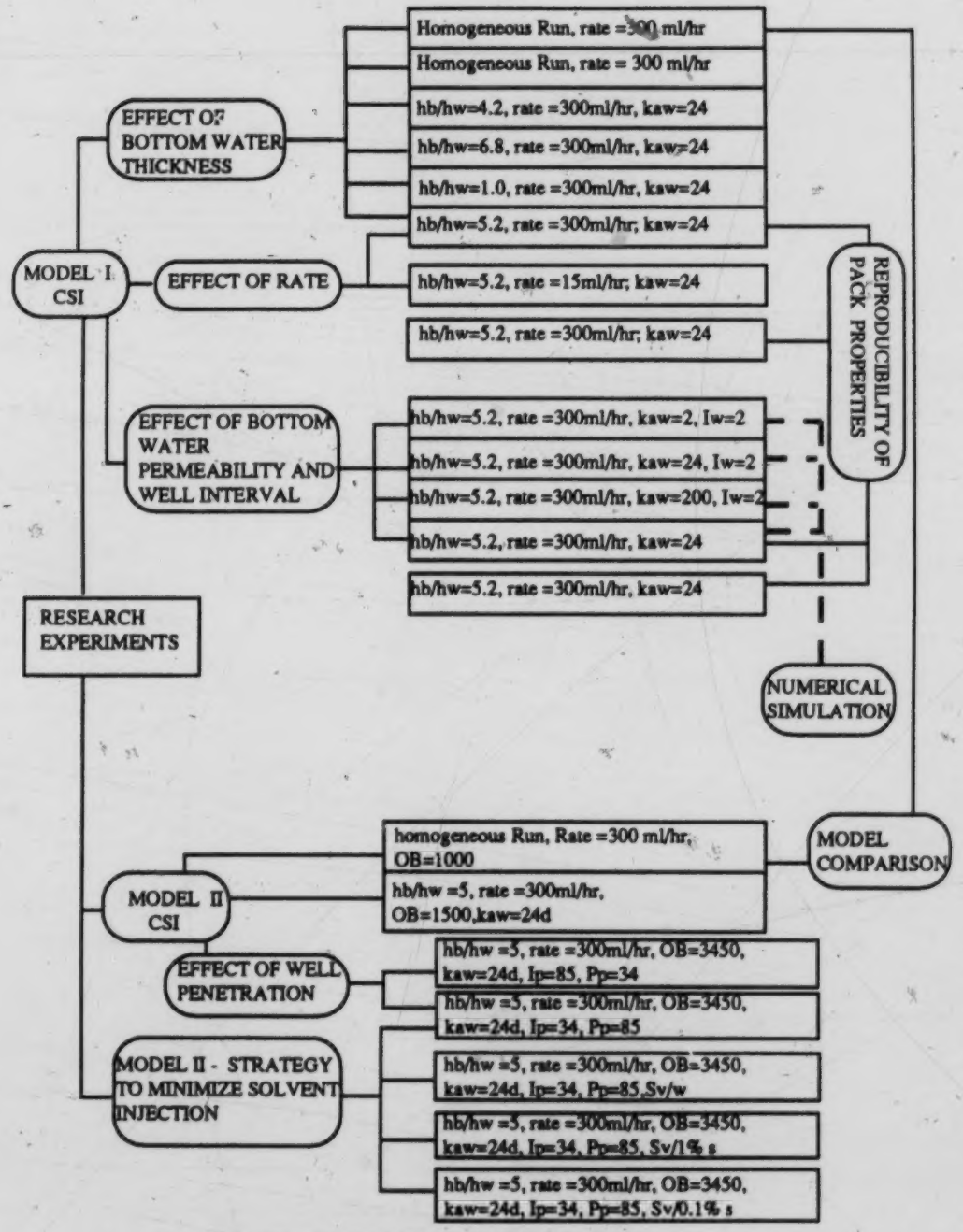
Table 5.1

Summary of Runs for the Recovery of Bitumen under Bottom Water Conditions

Comments			Model Parameters			Experimental Parameters							Results	
Run #	Type of Model	Process Description	Average Porosity %	keff. — μm**2	Bitumen Sat. % PV	hb/hw — Ratio	OB — kPag	Rate — ml/Hr	Ip,Pp % OS depth	Use of 2nd Inj. well	kaw — μm**2	Solvent Inj. HCPV	Bitumen Rec. % OBIP	Solvent Rec. % inj.
1	MI	CSI	39.1	0.2	75.1	∞	N/A	300	50, 50	N	—	3.0	14.7	96.4
2	MI	CSI	38.0	0.2	75.6	∞	N/A	300	60, 60	N	—	2.1	11.7	92.9
3	MI	CSI	38.6	1.7	62.6	4.2	N/A	300	60, 60	N	24	3.0	9.7	87.0
4	MI	CSI	39.7	3.4	63.4	6.8	N/A	300	60, 60	N	24	3.0	7.6	90.0
5	MI	CSI	39.6	9.6	36.8	1.0	N/A	300	60, 60	N	24	3.0	4.3	60.0
6	MI	CSI	37.6	2.0	67.5	5.2	N/A	300	60, 60	N	24	3.0	9.9	89.0
7	MI	CSI	34.5	3.7	77.9	5.2	N/A	300	60, 60	N	24	3.0	4.4	90.0
8	MI	CSI	38.2	2.7	66.5	5.2	N/A	15	60, 60	N	24	1.5	9.9	75.6
9	MI	CSI	40.2	1.9	56.5	5.2	N/A	300	48, 60	Y	2	3 , 6	26.7,41.2	83, 91
10	MI	CSI	40.8	4.7	55.9	5.2	N/A	300	48, 60	Y	24	3, 6	24.7,35.9	80, 89
11	MI	CSI	40.3	5.5	54.2	5.2	N/A	300	48, 60	Y	200	3, 6	3.8, 12	87.6, 93
12	MI	CSI	41.4	3.6	51.2	5.2	N/A	300	48, 60	N	24	3, 6	9.2, 17.9	84, 92.9
13	MI	CSI	40.6	12.2	56.5	5.2	N/A	300	48, 60	N	24	3	8.22	86.6
14	MII	CSI	39.0	0.6	68.0	∞	1000	300	28, 71	N	—	2.5	31.0	76.5
15	MII	CSI	36.0	5.5	75.0	5.0	1500	300	34, 85	N	24	2.5	34.7	69.3
16	MII	CSI	40.0	1.3	59.0	5.0	3450	300	85, 34	N	24	2.5	3.5	84.0
17	MII	CSI	39.0	1.2	56.0	5.0	3450	300	34, 85	N	24	2.5	14.6	75.7
18	MII	Sv/w (3 cycles)	39.5	1.2	59.0	5.0	3450	300	34, 85	N	24	1.47(2.5)*	6.8	75.5
19	MII	Sv/s-1% (3-cycles)	39.4	1.0	58.0	5.0	3450	300	34, 85	N	24	1.4 (2.5)*	11.3	71.0
20	MII	Sv/s-0.1%(3 cycles)	37.5	0.6	61.0	5.0	3450	300	34, 85	N	24	1.69(2.5)*	10.2	71.5

Abbreviations and Symbols

MI, MII	Model I, Model II	Sv	Solvent	N/A	Not Applicable
OS	Oil Sand	s	Surfactant	kaw	Absolute Permeability to Water
CSI	Continuous Solvent Injection	∞	Homogeneous Layer	OB	Overburden
HCPV	Hydrocarbon Pore Volumes	Y	Yes	Ip,Pp	Injection, Production Well Penetration
OBIP	Original Bitumen in Place	N	No	hb/hw	Oil sand - to - Bottom water Thickness Ratio
w	Water	*	Total HCPV's Fluid Inj.	Keff	Effective Permeability to Water


RESEARCH EXPERIMENTS
MODEL I CSI
EFFECT OF BOTTOM WATER THICKNESS
Homogeneous Run, rate =300 ml/hr
Homogeneous Run, rate = 300 ml/hr
hb/hw=4.2, rate =300ml/hr, kaw=24
hb/hw=6.8, rate =300ml/hr, kaw=24
hb/hw=1.0, rate =300ml/hr, kaw=24
hb/hw=5.2, rate =300ml/hr, kaw=24
EFFECT OF RATE
hb/hw=5.2, rate =15ml/hr, kaw=24
hb/hw=5.2, rate =300ml/hr, kaw=24
EFFECT OF BOTTOM WATER PERMEABILITY AND WELL INTERVAL
hb/hw=5.2, rate =300ml/hr, kaw=2, Iw=2
hb/hw=5.2, rate =300ml/hr, kaw=24, Iw=2
hb/hw=5.2, rate =300ml/hr, kaw=200, Iw=2
hb/hw=5.2, rate =300ml/hr, kaw=24
hb/hw=5.2, rate =300ml/hr, kaw=24
REPRODUCIBILITY OF PACK PROPERTIES
NUMERICAL SIMULATION
MODEL COMPARISON
MODEL II CSI
homogeneous Run, Rate =300 ml/hr, OB=1000
hb/hw =5, rate =300ml/hr, OB=1500,kaw=24d
EFFECT OF WELL PENETRATION
hb/hw =5, rate =300ml/hr, OB=3450, kaw=24d, Ip=85, Pp=34
hb/hw =5, rate =300ml/hr, OB=3450, kaw=24d, Ip=34, Pp=85
MODEL II - STRATEGY TO MINIMIZE SOLVENT INJECTION
hb/hw =5, rate =300ml/hr, OB=3450, kaw=24d, Ip=34, Pp=85,Sv/w
hb/hw =5, rate =300ml/hr, OB=3450, kaw=24d, Ip=34, Pp=85, Sv/1% s
hb/hw =5, rate =300ml/hr, OB=3450, kaw=24d, Ip=34, Pp=85, Sv/0.1% s

NOTE: CSI = CONTINUOUS SOLVENT INJECTION.

Figure 5.1: Guide to the Experiments Conducted.

(bitumen plus solvent). The volumes of the two layers were noted after centrifuging and the separated organic layer was analyzed for bitumen concentration after being dewatered with a 50% calcium chloride solution. This data was processed using the Microsoft-Excel program.

5.2 Presentation of Results

5.2.1 Production History

The production history for each run is presented in both tabular and graphical forms. The tables listed in Appendix B describe the model parameters as well as the experimental variables. It should be noted that Model I did not allow for the application of any overburden pressure. Well penetration was kept constant when studying the effect of a particular variable and therefore no mention of penetration is made in the production data tables except when it was a variable. The use of a second injection well is indicated in the appropriate tables and figures. Solvent injected in ml as well as in hydrocarbon pore volumes, HCPV, fluid and hydrocarbon produced in ml, pressure profile, bitumen concentration in the produced hydrocarbon (vol%), instantaneous solvent-oil ratio, SOR, water-oil ratio, WOR, cumulative bitumen (% OBIP) and solvent (% solvent injected) recoveries are presented in the tables. This format is changed slightly for the combination runs. The total fluid volumes injected (ml, HCPV), The instantaneous water-hydrocarbon ratio, WHCR, as well as the total solvent injected (HCPV) are presented along with the pressure, concentration and recoveries.

The production history of all runs is presented in Appendix C. There are four curves for each run. Solvent or fluid injected (HCPV) is plotted on the x-axis. In most of the runs the pressure profile, bitumen concentration and cumulative % original bitumen in place (OBIP) recovered are plotted on the right y-axis while the cumulative solvent recovery (% of solvent injected) is plotted on the left y-axis. For Runs 14 and 15 the injection pressure

is plotted on the right y-axis while the recoveries and concentration are plotted on the left y-axis. In Runs 16-20 the injection pressure and solvent recovery are plotted on the right y-axis while bitumen recovery is plotted on the left y-axis.

5.2.2 Volumetric Balance

The individual components of the produced effluent as well as the total effluent produced are plotted vs. actual injection volume. The total effluent produced curve is compared with the 'ideal' curve as shown in Fig 5.2. The ideal curve is one in which the injected volume is equal to the produced volume. The difference between the two curves serves as a measure of experimental error. The error is mostly due to the coarse scale on the injection pump and the centrifuge tubes. These errors will be discussed later in the chapter. A volumetric balance curve for every third experiment is presented in Appendix D.

5.3 Typical Run History

A typical run history will be described for Run 4. This experimental run was one of the set describing the effect of bottom water thickness on bitumen recovery. It was conducted in Model I and the oil zone-to-bottom water thickness ratio, h_b/h_w, was set at 6.8. Suncor synthetic crude was injected continuously at a rate of 300 ml/hr until at least three HCPV's solvent had been injected. Table 5.2 lists the injection pressure, instantaneous and cumulative bitumen recovery and solvent recovery of the run which are plotted against solvent injected in Fig. 5.3.

Looking at the figure, one observes that the pressure initially increased rapidly to a peak value of 36 kPa, at which time bitumen breakthrough occurred. After breakthrough, injection pressure dropped sharply and reached half its peak value upon the injection of 0.5 HCPV solvent, before stabilizing to a gradual decrease. The concentration profile followed a similar trend: a rapid decrease from the peak concentration of 29%, followed by a very

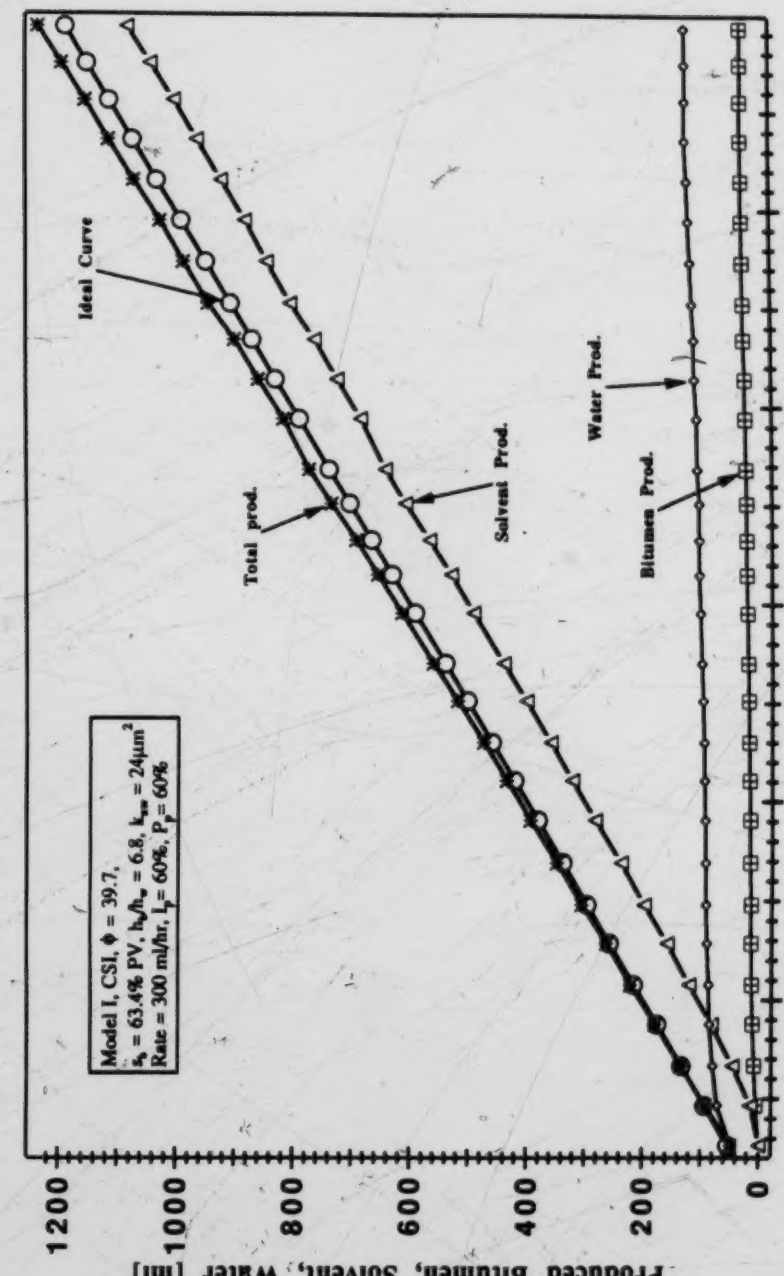


Figure 5.2: Volumetric Balance for Run 4 - Effect of Bottom Water Thickness.

TABLE 5.2

PRODUCTION HISTORY FOR RUN 4 - Effect of Bottom Water Thickness
[Model I, CSI, hb/hw=6.8, kaw=24μm2]

Porosity = 39.7%
Bitumen saturation = 63.4%
keff to water = 3.4μm2

Wt. sand pack = 2432.0 g
Wt. glass bead pack = 291.3g
Bitumen in place = 373.3 g

Rate = 300 ml/hr
BT Volume = 55.5 ml
BT pressure (gauge) = 36.3kPa

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT. recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	53.0	49.0	0.0	0.0	—	0.0	0.00	0.00	36.30	0.14
2	93.0	43.0	20.0	29.0	4.0	2.4	1.57	15.27	22.30	0.25
3	133.0	42.0	34.0	9.0	2.6	10.1	2.40	33.94	18.90	0.36
4	175.0	44.0	39.0	7.0	1.8	13.3	3.14	46.52	17.30	0.47
5	215.0	42.5	40.5	4.0	1.2	24.0	3.58	55.95	16.00	0.58
6	257.0	42.0	39.0	2.0	3.8	49.0	3.79	61.68	15.20	0.69
7	296.0	42.0	40.0	2.0	2.5	49.0	4.00	66.79	14.60	0.80
8	338.0	43.0	42.0	4.0	0.6	24.0	4.46	70.42	14.20	0.91
9	381.0	46.0	44.5	0.0	—	—	4.46	74.15	13.90	1.03
10	421.0	40.3	40.0	1.0	0.7	99.0	4.57	76.52	13.80	1.14
11	460.0	40.0	39.0	4.0	0.6	24.0	4.99	78.17	13.70	1.24
12	502.0	44.5	42.0	1.0	6.0	99.0	5.10	79.91	13.50	1.36
13	540.0	41.5	40.0	3.0	1.3	32.3	5.43	81.47	13.70	1.46
14	591.0	54.0	52.0	2.0	1.9	49.0	5.71	83.06	13.70	1.60
15	630.0	41.0	39.0	2.0	2.6	49.0	5.92	83.99	12.80	1.70
16	665.0	37.0	37.0	1.0	0.0	99.0	6.02	85.08	12.40	1.80
17	702.0	41.5	41.5	1.0	0.0	99.0	6.13	86.45	12.40	1.90
18	737.0	44.5	42.0	3.0	2.0	32.3	6.48	87.87	12.40	1.99
19	788.0	42.0	40.5	1.0	3.7	99.0	6.58	87.27	12.30	2.13

TABLE 5.2 (CONTINUED)

PRODUCTION HISTORY FOR RUN 4 - Effect of Bottom Water Thickness
[Model I, CSI, hb/hw=6.8, kaw=24μm2]

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
20	828.0	43.0	40.5	0.0	—	—	6.58	87.94	12.10	2.24
21	868.0	42.5	42.0	4.0	0.3	24.0	7.04	88.54	12.10	2.35
22	905.0	42.5	40.0	1.0	6.3	99.0	7.15	89.29	12.10	2.45
23	947.0	39.5	37.0	1.0	6.8	99.0	7.25	89.20	11.70	2.56
24	989.0	42.5	40.0	1.0	6.3	99.0	7.36	89.42	11.70	2.67
25	1030.0	44.0	41.5	1.0	6.0	99.0	7.47	89.85	11.70	2.78
26	1071.0	43.0	41.0	1.0	5.1	102.8	7.58	90.20	11.70	2.89
27	1111.0	40.0	39.5	1.0	1.3	97.8	7.68	90.47	11.90	3.00
28	1149.0	40.0	40.0	1.0	0.0	99.0	7.79	90.92	11.90	3.11
29	1186.0	40.5	40.0	1.0	—	—	7.79	91.46	11.90	3.21

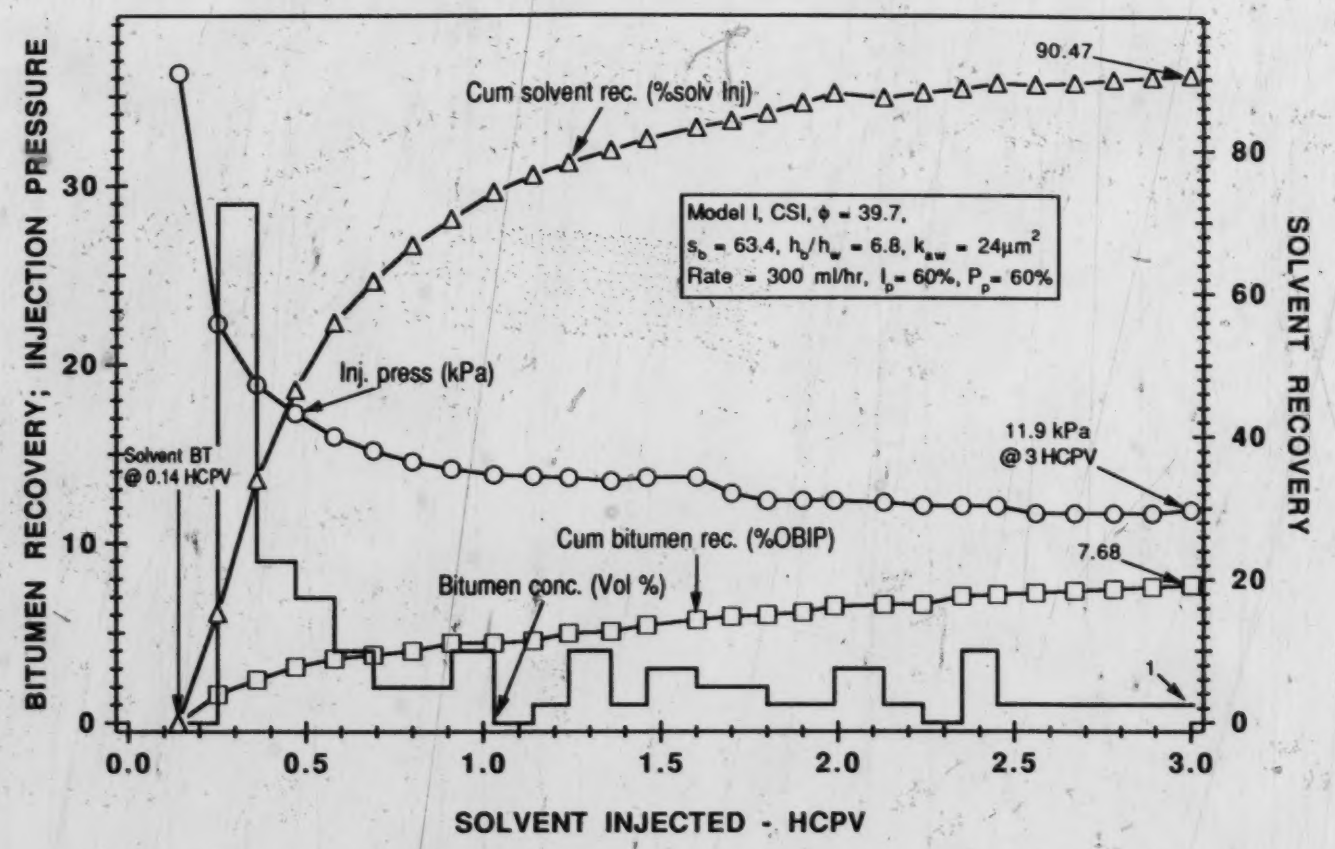


Figure 5.3: Production History for Run 4 - Effect of Bottom Water Thickness.

gradual change in bitumen concentration. The cumulative bitumen recovery curve had a large slope initially corresponding to rapid bitumen dissolution by leaching, followed by a gentle slope corresponding to the dissolution of bitumen by diffusion to give a total recovery of 7.7% OBIP after the injection of 3 HCPV's solvent. These three curves are plotted using the scale on the left y-axis, while the cumulative solvent recovery vs. HCPV's solvent injected is plotted on the right axis. The solvent recovery curve increased sharply initially and then more gradually, essentially in inverse relationship to the injection pressure.

5.4 Post Run Analysis

Visual inspection of the post run core showed that in most cases, the areas close to the injection and production ends as well as the area adjacent to the bottom water zone had most of the bitumen leached from it, while the area in the middle was similar to the original bitumen, although it appeared to have had some contact with the injected solvent. The bottom water zone was saturated with mobilized bitumen. The residual bitumen saturation was found by dividing the core into eight sections and extracting it as described in the experimental section. The bitumen content of the extract was determined using Cragoe's method.[45] This was done by determining the viscosities of the mixture, bitumen and Synthetic crude at room temperature and calculating the linear function of the mixture, L_m, bitumen, L_b, and Synthetic crude, L_s, from Equation 5.1. The weight fraction of bitumen in the extracted sample was calculated from Equation 5.2. Run 10 showed a considerably higher recovery than the other runs, and thus the residual bitumen saturation profile along the core was more pronounced, and is presented in Fig. 5.4.

$$L = \frac{1000 \ln 20}{\ln \mu - \ln(5 \times 10^{-4})} \quad \text{.....} \quad (5.1)$$

$$L_m = f_b L_b + (1 - f_b) L_s \quad \text{.....} \quad (5.2)$$

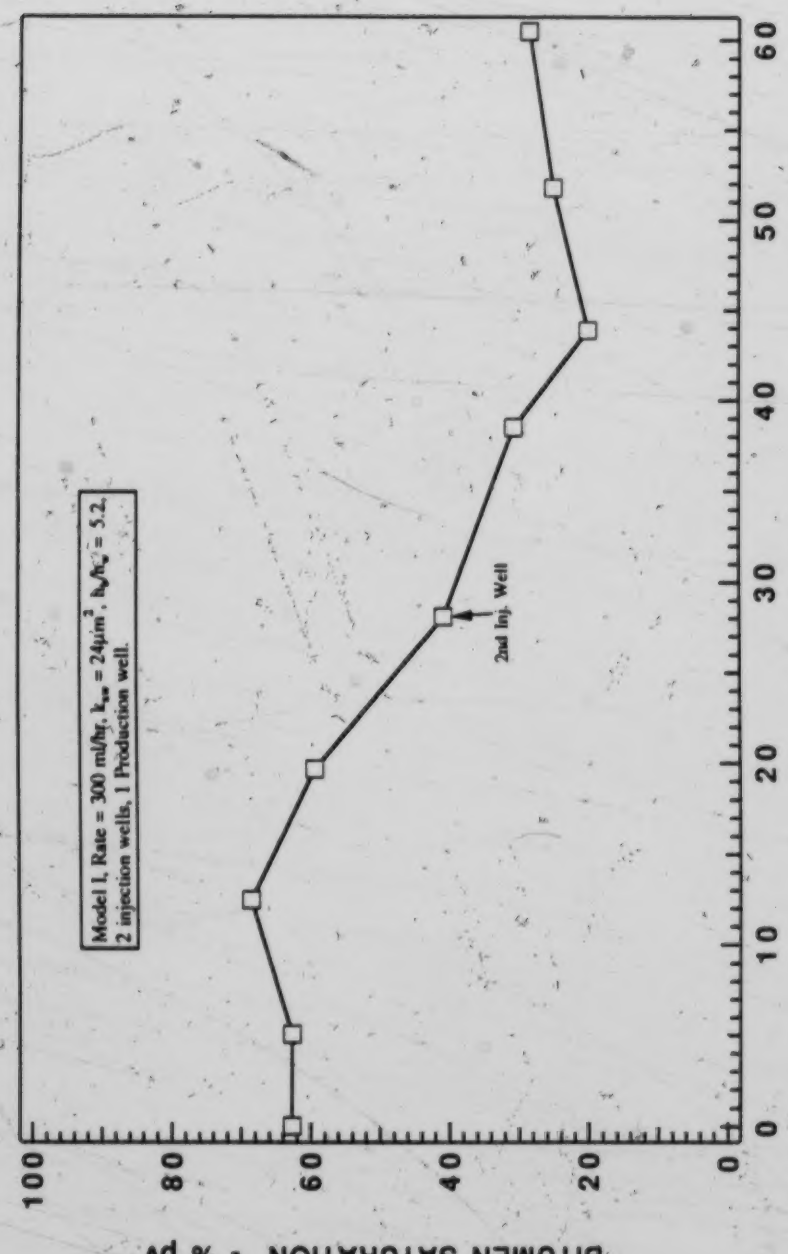


Figure 5.4: Residual Bitumen Saturation Profile for Run 10.

5.5 Mechanism for Bitumen Leaching in the Presence of Bottom Water

Based on experimental observations an explanation of the mechanism for bitumen leaching has been proposed and is illustrated pictorially in Fig. 5.5

Step 1: Continuous solvent injection starts. Solvent dissipates into the oil sand layer near the injection well.

Step 2: Mobilized bitumen moves through the bottom water layer. Rate of dissolution is faster than the rate of transport, resulting in the formation of an effluent bank which is monitored as an increase in injection pressure. The mobilized bitumen displaces water from the bottom water zone to the producer.

Step 3: Leaching takes place by both dissolution and diffusion. Diffusion, while comparatively slow, is the dominant mechanism. Consequently, the bitumen is removed at a faster rate than the rate at which it is mobilized, indicated by the decrease in bitumen concentration after the initial peak concentration.

Step 4: Diffusion is the only recovery mechanism in effect. The comparatively high injection and production rates result in very little diffusion taking place and as a result, the leaching process is nearly at the end as indicated by the extremely low bitumen concentration in the effluent and the nearly constant pressure.

5.6 Types of Runs Conducted

Six different types of runs were conducted to study the parameters that might affect bitumen recovery in the presence of bottom water. These were:

1. Bottom water zone thickness;
2. Residence time (rate);
3. Bottom water zone permeability;

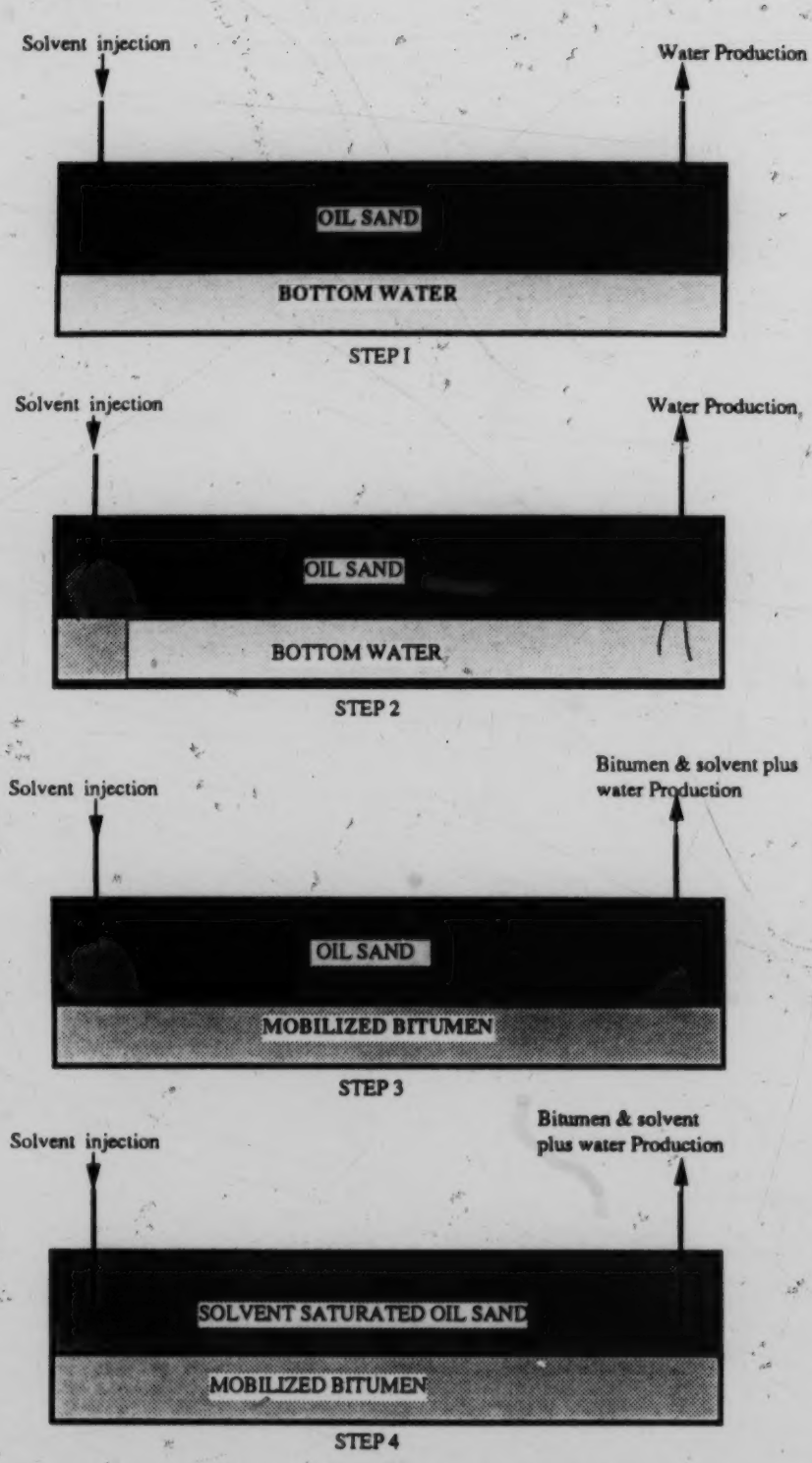


Fig. 5.5: Mechanism for Bitumen Leaching in the Presence of Water.

4. Well completion interval;
5. Well penetration;
6. Injection/production strategy.

5.7 Model 1 Runs

5.7.1 Effect of Bottom Water Thickness

Two basic types of runs were conducted to study the effect of bottom water thickness on recovery. These were :

1. Homogeneous Pack Runs - these were runs in which the in-place bitumen was mobilized by means of a solvent in the absence of any initial channel, i.e. the pack consisted of oil sand only.

2. Bottom Water Runs - a bottom water zone was created below the oil sand zone.

Homogeneous Pack Runs

Runs 1 and 2 were homogeneous pack runs. The purpose of these runs was three-fold:

i) To have a base run with which to compare the bottom water runs;
ii) To establish a method of data acquisition and analysis;
iii) To evaluate the performance of the experimental apparatus.

The experimental parameters for the two runs were similar except for the injection and production well penetrations, which were set at 50% of oil sand depth for the first run, and 60% for the second run. Solvent was injected continuously in these runs; and the production histories of the two runs are given in tabular form in Tables B1 and B2 and are plotted in Figs. C1 and C2.

The recoveries for the two runs were very similar (11.7% OBIP at ~2 HCPV's solvent injected), although the breakthrough volumes are different. The observation of a channel in

the middle of core 1 indicated that it may have served as a path for the solvent to channel to the producer, resulting in the correspondingly early breakthrough and overall low injection pressure. The difference in well penetration does not appear to have a significant effect.

Bottom Water Runs

The next four runs (Runs 3 to 6) involved displacement of bitumen in packs having a bottom water layer. The purpose of these runs was to determine the effect of bottom water thickness on bitumen recovery. The experimental parameters that were fixed for the four runs were: injection rate at 300 ml/hr; bottom water permeability of 24 μm^2 and well penetration at 60% oil sand depth. The oil sand composition was determined prior to each run as it can vary considerably. Bitumen content varied between 13.7 to 15.5% by wt. The porosities of the packs were 39% $\pm$ 1%. The ratios of oil sand-to-bottom water [h_b/h_w] thickness examined were: h_b/h_w =1.0, 4.2, 5.2 and 6.8.

The individual production histories of the four runs are presented in tabular form in Tables B3 to B6 and in graphical form in Figs. C3 to C6. In general, low h_b/h_w ratios resulted in low injection pressures and high solvent injection volumes before bitumen breakthrough because of the larger volume of water that had to be displaced. It was found that the bottom water zone thickness has an effect on the overall bitumen recovery. Bottom water in general serves as a path for bitumen transport to the producer, resulting in lower injection pressures than when there is no bottom water zone present.

Two limitations of Model I made it difficult to examine h_b/h_w ratios other than those mentioned previously and thus locate the limiting ratio where the bottom water zone was no longer advantageous for bitumen recovery. These limitations were: the location of the end-port which was used for packing the bottom water zone. The end-port was located in the center and tends to be covered with oil sand when high h_b/h_w ratios are investigated making

it difficult to pack the bottom water zone. The second limitation was the depth of the model and the packing technique. A difference of 0.1 cm can cause a significant error in the h_b/h_w ratio. Comparing the effect of bottom water thickness on recovery, it was found that the recoveries (7.7 to 9.7%) for h_b/h_w ratios between 4.2 and 6.8 did not vary significantly, while for a h_b/h_w ratio of 1.0 the recovery of 4.4% OBIP was almost half of that in the other three runs.

Figure 5.6 gives a comparison of the cumulative bitumen recovery for the different bottom water runs and the homogeneous pack (i.e. no bottom water present) run. In Run 1 (homogeneous pack run) the recovery upon the injection of 2.97 HCPV solvent was 14.7% OBIP, while the recovery (9.9% OBIP) for Run 6 (h_b/h_w=5.2) was approximately two-thirds of that in Run 1. Run 5 (h_b/h_w=1.0) exhibited the lowest recovery(4% OBIP). Figure 5.7 presents the solvent recovery for the above runs. Notice that almost 40% of the solvent injected was unrecovered in Run 5 (h_b/h_w =1.0), while only 10% of solvent injected was unrecovered for the h_b/h_w = 5.2 case (Run 6) after the injection of three HCPV's of solvent, which indicates that a thick bottom water layer leads to excessive channelling of the solvent and comparatively low bitumen and solvent recoveries.

5.7.2 Effect of Residence Time

From the previous runs it was conjectured that solvent diffusion into bitumen was the dominant process in bitumen recovery. To verify this premise, a low injection rate of 15 ml/hr was used in Run 8 in contrast to the previous injection rate of 300 ml/hr. Note that although the injection rate was the apparent variable, the real variable was the residence time, since the fluids were in contact with the bitumen for a longer period. All other experimental parameters were kept the same as in Run 6 as indicated in Table 5.1. The results of the run are presented in Table B8 and are plotted in Fig. C8.

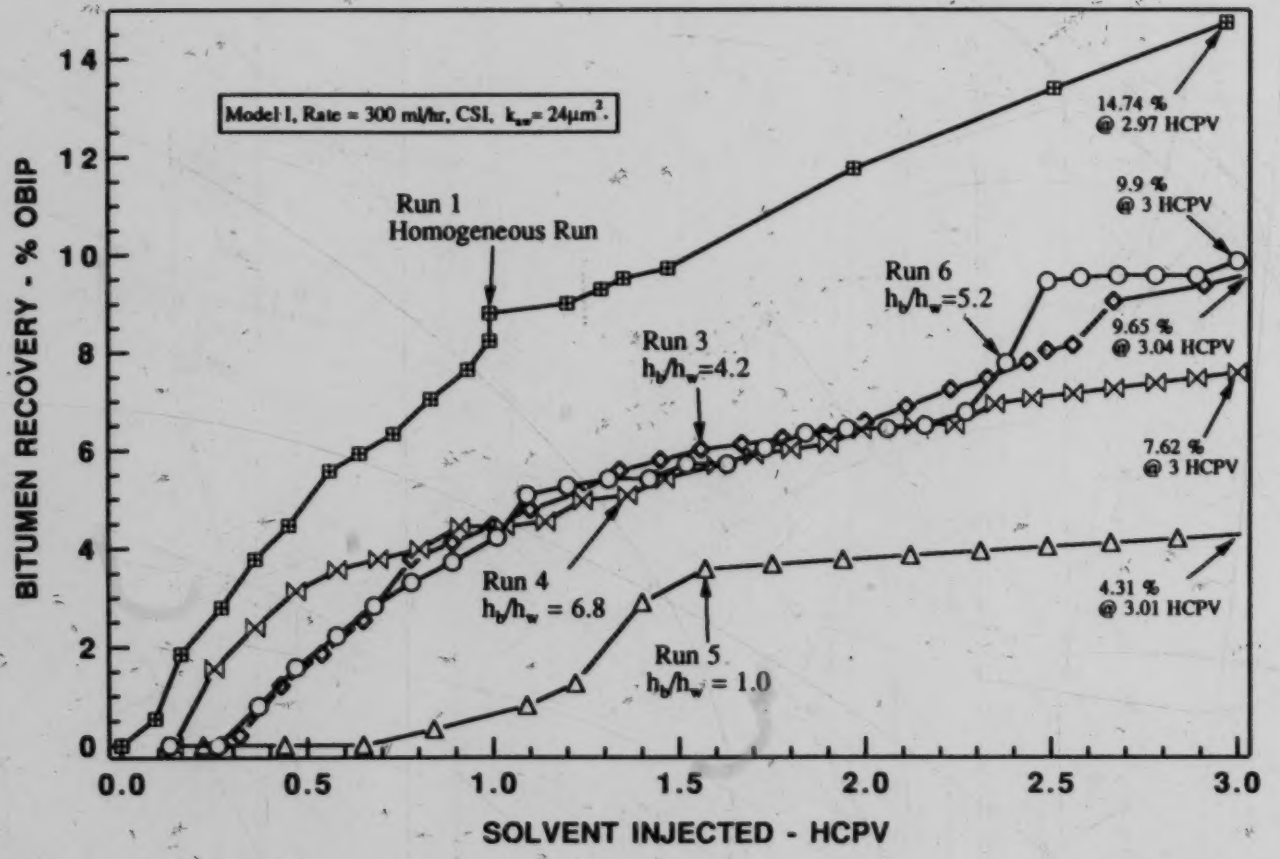


Figure 5.6 : Effect of Bottom Water Thickness on Bitumen Recovery.

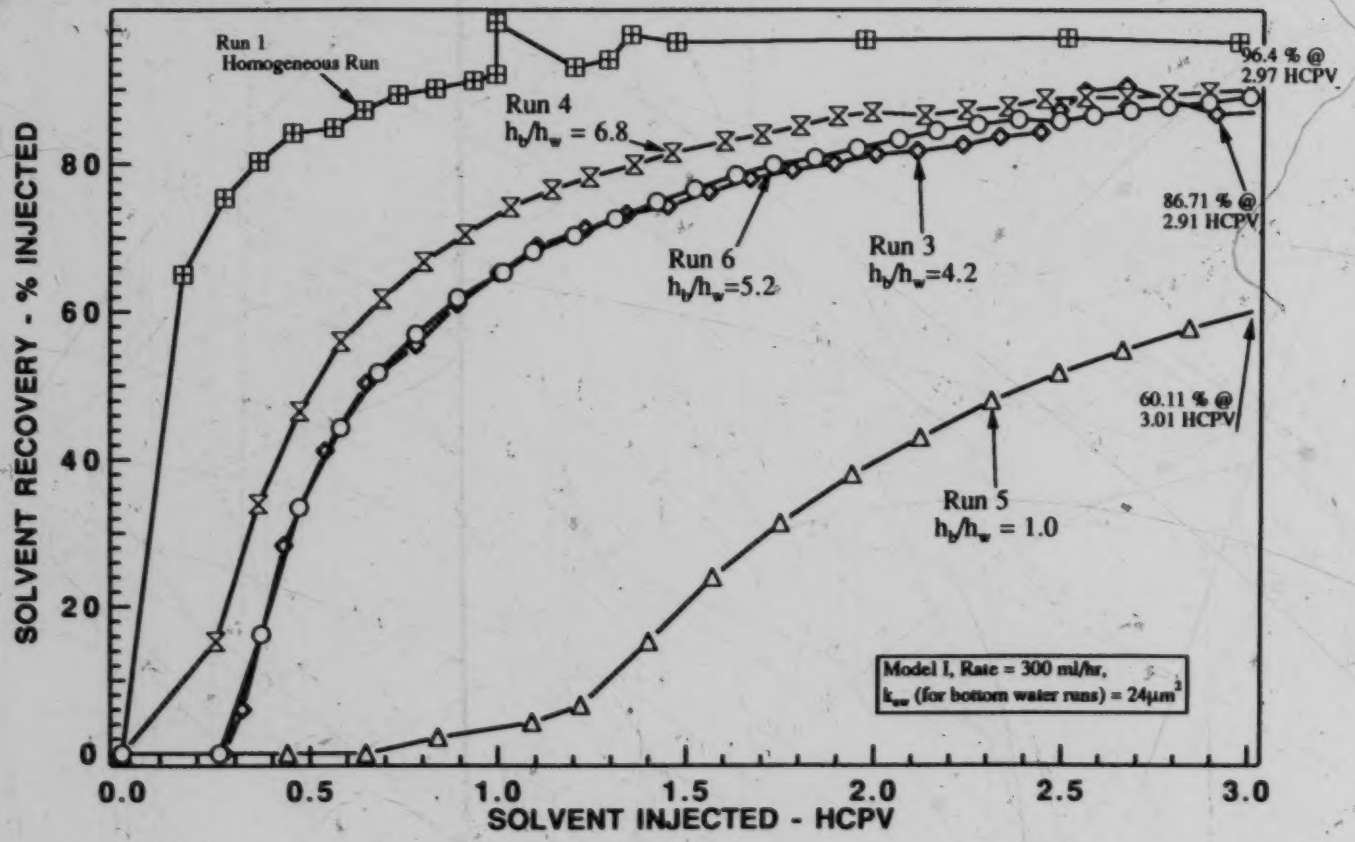


Figure 5.7: Effect of Bottom Water Thickness on Solvent Recovery.

From Fig. C8, It is seen that the bitumen concentration in the effluent remained between 12 to 15% until 0.5 HCPV of solvent had been injected, after which it dropped to 6% and then to 3% at 1.26 HCPV's solvent injected. At this point (point A), it was decided to stop injection and let the porous pack soak for a period of 65 hrs. The effluent collected after the soak period was considerably more concentrated than that before injection was stopped. The pressure increased initially due to bitumen banking, but soon dropped to the value before injection was stopped.

The increase in pressure and bitumen concentration in the effluent were a result of the bitumen mobilization, and its subsequent banking and then channelling into the bottom water zone, from where it was transported to the production well. The recoveries for Runs 6 and 8 are plotted in Fig. 5.8. The cumulative bitumen recovery of 9.9% OBIP after 1.5 HCPV's of solvent had been injected at the lower rate was comparable to that after the injection of 3 HCPV's at the higher rate in Run 6. The difference in the recoveries of the two runs for the same amount of solvent injected, suggests that diffusion does indeed play an important role in bitumen recovery.

5.7.3 Effect of Bottom Water Zone Permeability

Three experiments, Runs 9, 10 and 11 were conducted to determine the effect of bottom water zone permeability on bitumen recovery. A h_b/h_w ratio of 5.2, injection well penetration, Ip, of 48% oil sand depth, production well penetration, Pp, of 60% oil sand depth, and an injection rate of 300 ml/hr were employed in all three runs. In all three cases there was an additional injection well in the middle. After 3.5 HCPV's of solvent had been injected, the end injection well was shut in and the solvent was then injected through the middle injection well.

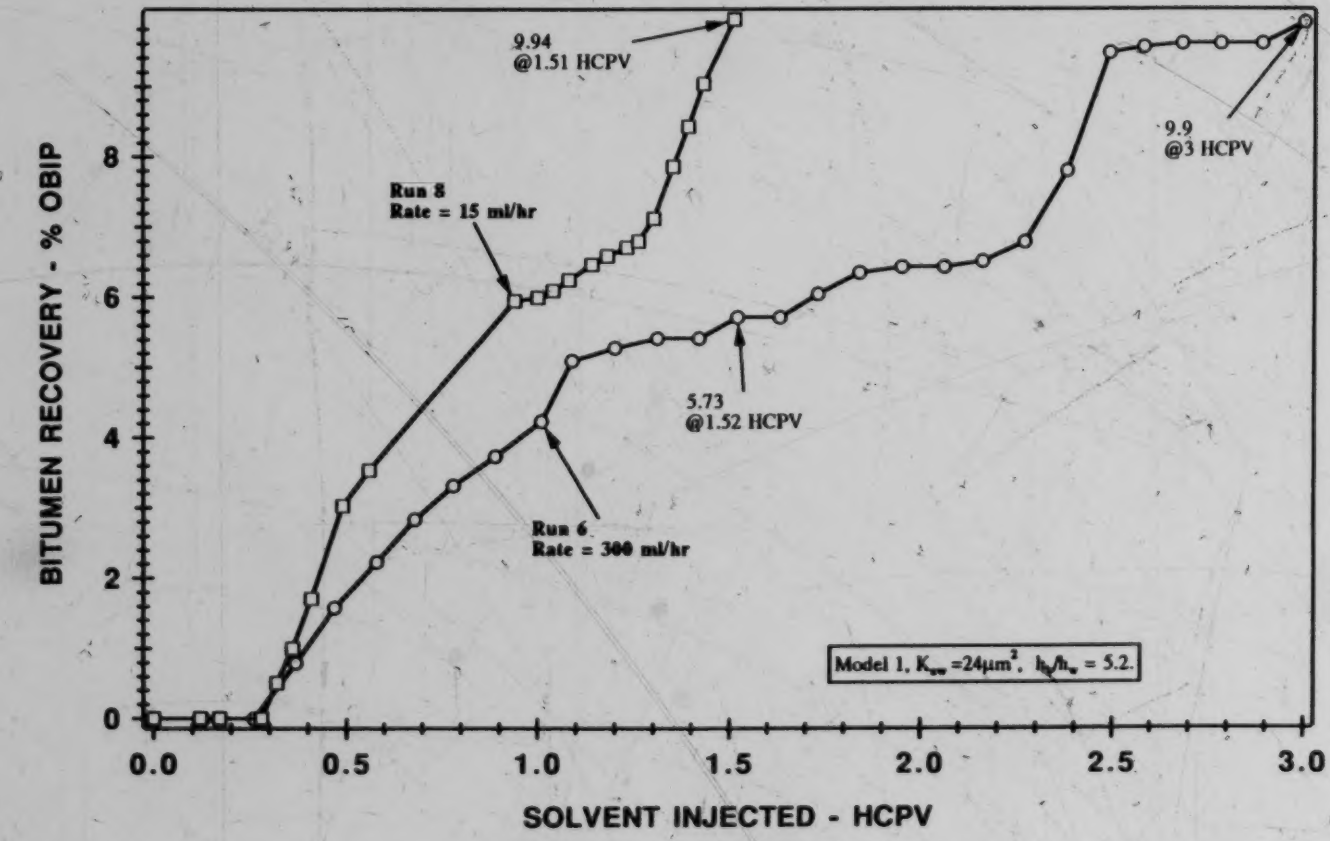


Figure 5.8: Effect of Rate on Bitumen Recovery.

Three different sizes of glass beads were used for the bottom water zone; these were: mesh size 170-325 which had an absolute permeability of 2 μm^2 to water [Run 9]; mesh size 70-100 with an absolute permeability of 24 μm^2 to water [Run 10]; and mesh size 20-30 with an absolute permeability of 200 μm^2 to water [Run 11]. The model parameters (porosity and bitumen saturation) for the three experimental runs were within 2% as observed in Table 5.1. The first part of the runs (up to 3.5 HCPV's solvent injected) was used to study the effect of bottom water permeability on bitumen recovery. An additional 2.5 HCPV's were injected through the middle injection well in order to study the effect of well completion interval.

Cumulative recoveries for the three runs are presented in Fig. 5.9 vs. solvent injected (HCPV). It was observed that the bottom water permeability had a significant effect on the ultimate bitumen recovery, which ranged from 4% OBIP (Run 11) to 27% OBIP (Run 9) at 3 HCPV's solvent injected. Run 9, with the lower bottom water zone permeability, showed the highest recovery (27%), while the higher permeability zone [Run 11], had the lowest (4%) recovery. Note that the permeability in Run 9 was a twelfth of that in Run 10, but the corresponding bitumen recovery after the injection of ≈2.9 HCPV's solvent was only ≈2% greater. In Run 11 (200μm^2), the permeability was over eight times that in Run 10 (24μm^2), while the recovery was a sixth of that in Run 10 (3.8% vs.24.78% OBIP). Thus, it would seem that there is a critical value after which channelling becomes a serious factor in recovery. The production histories of the individual runs are presented in Tables B9 to B11 and are plotted in Figs. C9 to C11.

Note that bitumen recovery in Run 10 (24.8% at 3 HCPV) was higher than in previous runs. The conditions in Run 10 were similar to those in Run 6, yet the recovery in Run 10 (24.8%) was more than twice that in Run 6 (9.9% at 3 HCPV). There are two possible explanations for this difference. The first one is the difference in injection well penetration

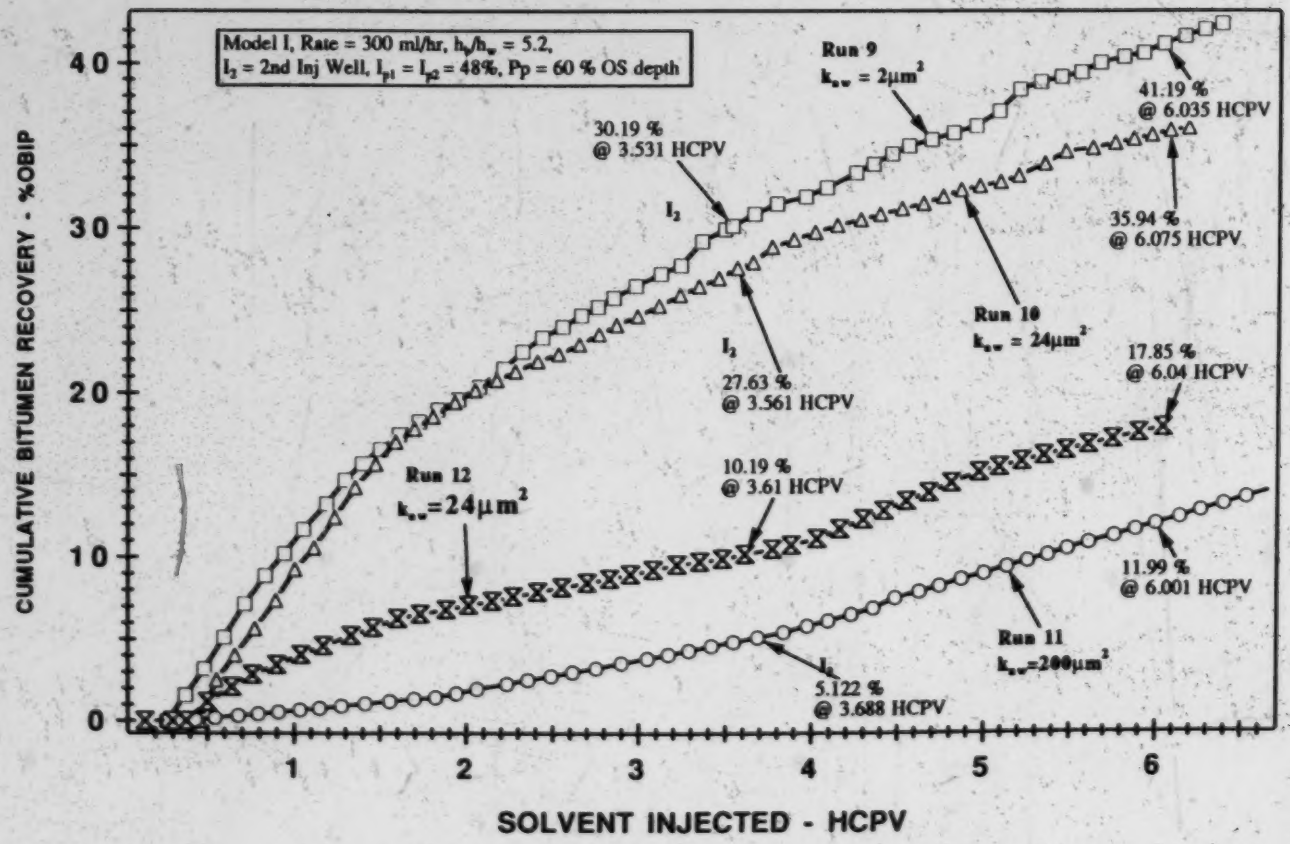


Figure 5.9: Effect of Bottom Water Permeability and Well Interval on Bitumen Recovery.

(Table 5.1). It is conjectured that this factor could not have affected recovery to such a large extent based on the recoveries from Run 12, (9.2%) which is a replicate of Run 10, except for the absence of the second injection well.

The well penetration in Run 12 was set at the same depth as in Runs 9 to 11, but the second well was omitted. In Run 10, 3.56 HCPV's of solvent were injected through the end injection well and another 2.5 HCPV's of solvent were injected through the middle well to make a total of 6 HCPV's of solvent. In Run 12, a total of 6 HCPV's of solvent were injected through the end injection well and the middle well was omitted as mentioned before. Recovery of 9.2%(3 HCPV) as shown in Fig. C12 versus 9.9% OBIP after 3 HCPV's solvent injected in Run 6 (Fig. C6) indicates that well penetration is not the significant factor in this case. The second explanation is that the packing around the second injection well was not as compact as in the rest of the core, making it more easily penetrable by the solvent, resulting in higher recovery.

Figure 5.10 shows a comparison with previous work done by Kaleli[32] for solvent displacement of bitumen in the presence of bottom water. Run 16 in Kaleli's[32] study is similar to Run 9 in the present study since sampling points used in Kaleli'as work are analogous to the second injection well in the present study. It is felt that this run is the one that can be compared to Kaleli's since the oil sand-to-bottom water thickness ratio of 5.2, the injection rate, and the glass beads used to simulate the bottom water are similar. The two sets of curves (bitumen and solvent recovery) appear to be relatively close, some of the discrepency can be explained by the slight difference in the well size and the variations in the oil sand properties from batch to batch.

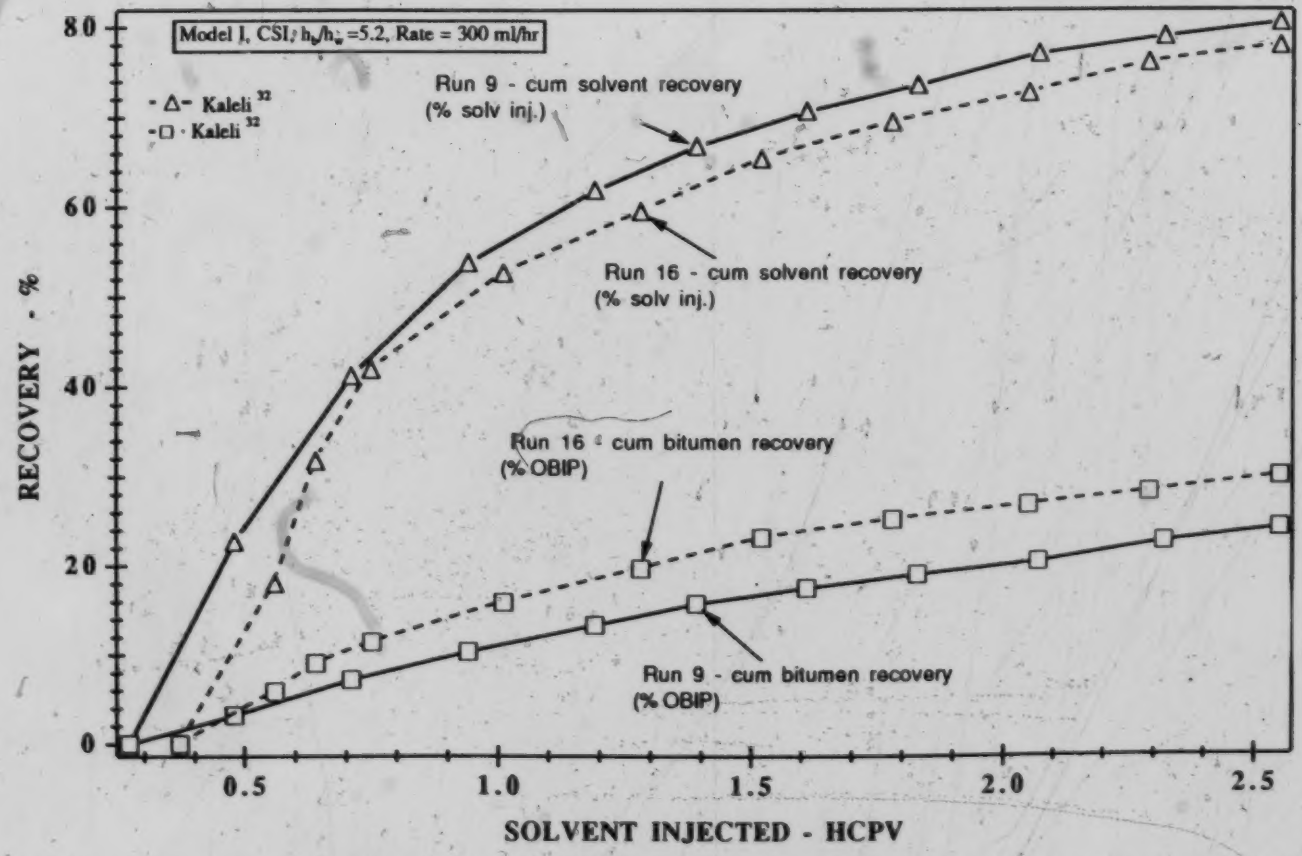


Figure 5.10: Comparison with Previous Work for Solvent Displacement of Bitumen in the Presence of Bottom Water.

5.7.4 Effect of Well Completion Interval

The above three experiments [Runs 9-11] were also part of a study to investigate the effect of different injection strategies on bitumen recovery. Conformance can be influenced by well spacing and well operating strategy; thus an additional injection well (infill drilling), incorporated between the injector and producer in an area that has been bypassed by the solvent, could substantially increase conformance and ultimate recovery. In Runs 1 to 8, it was observed that the solvent virtually bypassed the middle areas; therefore in Runs 9, 10 and 11 an additional injection well was incorporated in the middle [at 48% well penetration]. The experimental parameters were described in the previous section on the effect of bottom water permeability.

Up to 3.5 HCPV's of solvent were continuously injected through the end injection well, after which it was shut in and the solvent was then injected through the middle injection well. A fourth run in this series [Run 12] was conducted without an injection well in the middle, as a benchmark. The bottom water zone permeability in Run 12 was 24 μm^2 and the well penetrations were the same as in the other three runs.

The production histories in tabular and graphical forms are presented in Appendices B and C, respectively. The effect of the second well on bitumen recovery for the different permeabilities is shown in Fig. 5.9. Because of the unexpected high recovery (24.8% at 3 HCPV) in Run 10, which might have resulted from non-uniform packing around the second well, it was difficult to compare the same with the Run 12, which is the base run. The conditions in Run 12 were duplicated in Run 13 to determine if the high recovery in Run 10 was indeed due to non-uniform packing around the middle injection well. Recoveries for the two runs were similar (8.2% OBIP for Run 13 vs. 9.2% OBIP for Run 12) which suggests that the high recovery in Run 10 may indeed be a result of non-uniform packing around the middle well.

It was difficult to isolate the effect of decreasing the well distance by introducing the second injection well in both Runs 9 and 10, from the effect of non-uniform packing around the well as there does not seem to be any obvious difference in the recovery trend. However, inspection of the post run core indicated that most of the bitumen around the well areas had been leached and the bottom water layer was saturated with the mobilized bitumen, indicating that both factors were responsible. In the high bottom water permeability case, the effect of the second injection well was more pronounced. Figure C11 shows that bitumen recovery increased from 5.1% OBIP after 3.6 HCPV's solvent injected to 11.3% OBIP upon the injection of an additional 2.4 HCPV's from the middle injection well. The saturation profile of the post run core (Run 10) as a function of length is shown in Fig. 5.4.

5.7.5 Reproducibility of the Results

One of the problems of working with oil sand is that there are several variables that can affect the pack properties, some of which are difficult to control. For example the bitumen saturation in the pack can vary due to the varying oil sand composition, which in turn could affect porosity, permeability and the ultimate bitumen recovery. To account for this variability to some extent, the composition of the oil sand was determined prior to each run and the ultimate recoveries are given as percentages of the original bitumen in place. Another factor that could result in the slight variations in the model parameters and experimental results is the packing technique used for the oil sand and the bottom water zones, which was largely dictated by the model design.

The first two runs were conducted without any bottom water (homogeneous pack). It was found that the model parameters could be reproduced to within ± 1%. In the case of the bottom water runs at a h_b/h_w ratio of 5.25, two sets of duplicate runs were attempted. It

was possible to reproduce the model parameters to a large extent. For example, considering Runs 6, 7 and 8 [Ip = 60% Pp = 60%], the model parameters for Runs 6 and 8 were reproducible within 1%, but not so for Run 7. The comparatively low porosity indicates that the pack in Run 7 may have been packed tighter than that in Run 6. The low recovery might have been a result of the solvent channelling into the bottom water and bypassing most of the the oil sand, which could also be the reason why the injection pressure was low. Recoveries for Runs 6 and 8 could not be compared as the injection rates were different. Runs 12 and 13 were also duplicate experiments, with Ip of 48% and Pp of 60% and h_b/h_w ratio of 5.25. It was possible to reproduce the pack properties fairly well. As seen from Fig. 5.11, the cumulative bitumen recoveries for Runs 6, 12 and 13 ranged from 8.2% to 9.9% and the solvent recoveries ranged from 84 to 89%, which indicates that the reproducibility of the results was good.

5.8 Model II Runs

Model II, was a new model designed during the course of this study. It was longer and deeper than Model I, and allowed for better control in placing the wells. Specially designed wells with a specific penetration of the oil sand zone could be placed in the model after it was packed, which eliminated the problem of a non-homogeneous pack around the wells. The model also allowed for the application of an overburden pressure.

5.8.1 Homogeneous Pack Run

The first run conducted on Model II, (Run 14) employed a homogeneous pack. There were three reasons for conducting a homogeneous pack run: first, to develop a technique for packing the oil sand layer as well as to understand any problems or deficiencies in the model itself; second, to have a base run to compare the bottom water runs with; and third, to compare the two models, Model I and Model II.

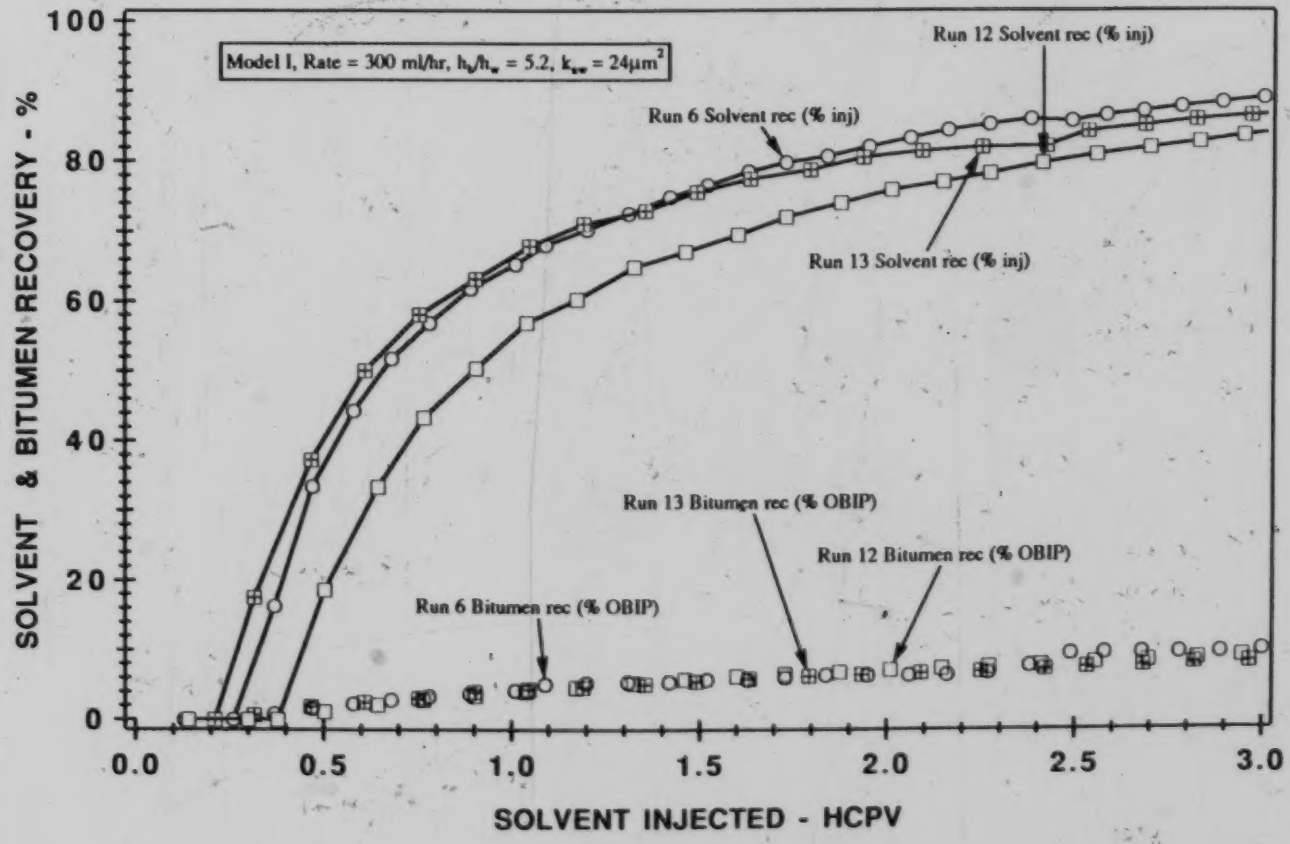


Figure 5.11: Reproducibility of Results.

Run 14 was conducted at a rate of 300 ml/hr and was concluded after three HCPV's of Suncor synthetic crude as solvent had been injected. The injection and production wells were located 3.5 cm from each end of the model. The injection well had a 28% penetration into the oil sand layer, while the production well had a 71% penetration in the oil sand layer. The overburden pressure was set at 1000 kPa. The effective permeability of the pack was 0.57 μm^2.

The production history for Run 14 is described in Table B14 and is plotted in Fig. C14. Notice that the pressure peaked at over 510 kPa and the pressure profile and the instantaneous bitumen produced curves have the same trend. The effluent was first observed just as the pressure was peaking. The effluent concentration was also a maximum at this point. As the pressure decreased, the effluent concentration decreased simultaneously. Bitumen recovery after the injection of approximately three HCPV's solvent was 34% OBIP (Original Bitumen In Place), while the solvent recovery was about 80% (solvent injected).

Inspection of the post run core showed that the injection side was the cleanest, followed by the production side as a result of bitumen leaching. The intermediate area was darker, but was saturated with solvent, indicating that the solvent had not found any obvious paths through which to bypass the oil sand layer. The sand was loose in some areas due to bitumen leaching, otherwise the pack was fairly homogeneous and tight.

5.8.2 Comparison of the Two Models

Models I and II were both rectangular models with a length to depth ratio of approximately ten. Several features were added on or improved in the new model to eliminate problems found in Model I. Three problems in Model I were greatly mitigated. First, solvent override and channelling were significantly reduced by moving the wells away from the

ends and by the application of an overburden pressure of up to 3450 kPa. Second, the wells could be drilled into the oil sand layer, thus allowing for a more uniform pack around the wells and better control in their placement. Third, the presence of a 'blank' makes it possible to pack the oil sand layer more uniformly and set the ratio of oil sand to bottom water layer more accurately. A comparison of the production histories of Runs 2 and 14 shows the effect of these improvements (Figs. C2 and C14) .

Although Run 14 followed the same trend as Run 2, which was a homogeneous pack run conducted on Model I, the peak pressure and the ultimate recoveries were different. The bitumen recovery in Model II was higher (27.1% OBIP at 2.1 HCPV) compared to Model I (11.7% OBIP), probably as a result of the homogeneity of the pack, especially around the wells, and the application of the overburden pressure, which stopped the solvent from bypassing the oil sand layer; consequently, solvent recovery was slightly lower than in Model I. The injection pressure was significantly higher as a result of the above two factors. The recovery profiles and the pressure histories of Runs 2 and 14 are compared in Figs. 5.12 and 5.13 respectively. Although the well penetrations were different in the two runs, it was not a significant factor in a homogeneous oil sand pack.

5.8.3 Bottom Water Run

The second run (Run 15) on Model II was for a 5:1 oil sand zone to bottom water zone thickness ratio. The purpose of the run was to develop a technique for packing the bottom water zone and to compare the recoveries obtained with those in the old model. The oil sand layer was packed as indicated in the chapter on experimental procedure. The glass bead layer [24μm^2] was wet packed vertically as in the old model. This run was very different from the previous runs in that the pressure profile peak was broader, i.e. the injection pressure remained at or close to the peak value for a longer time. The production history of the run is tabulated in Table B15. The peak value of 193 kPa was significantly

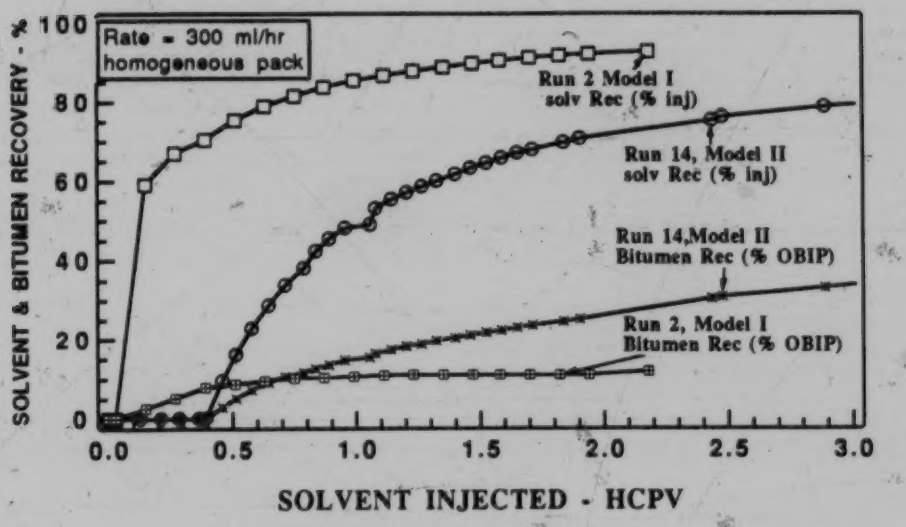


Figure 5.12: Comparison of Recoveries for the Two Models.

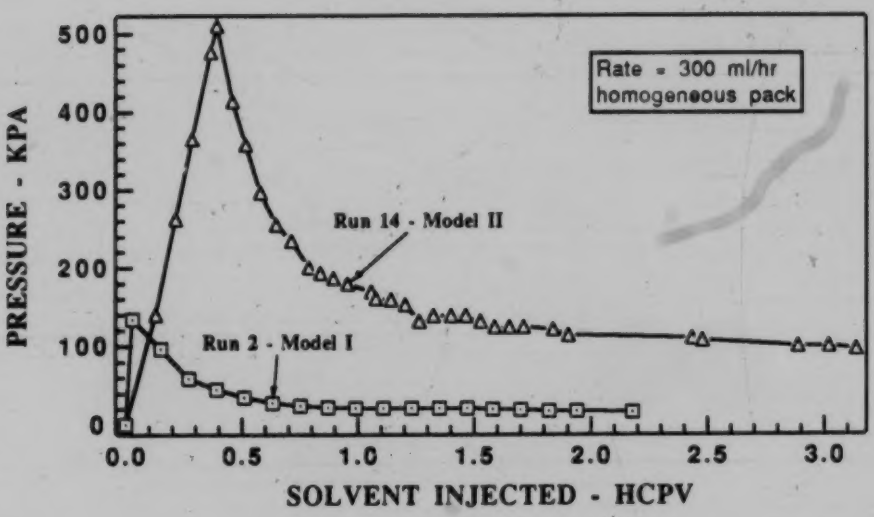


Figure 5.13: Comparison of Pressure Profiles for the Two Models.

lower than in the case of the homogeneous run. The effluent concentration did not decline to a low value as in other runs, instead it remained close to 20% until two HCPV's of solvent had been injected. The overall recovery of 42% after 3 HCPV's of solvent injected was higher than that in the case of the homogeneous pack run. The cumulative solvent recovery was about 74%.

Observation of the core on dismantling showed that the Neoprene diaphragm had pushed against the oil sand layer and as a result the bottom water zone covered only a third of the total length of the model, while the other two-thirds was covered with only a thin film of glass beads. In effect, this would be equivalent to blocking off two-thirds of the bottom water layer which would account for the unusual recovery and pressure profiles. Thus, the bottom water layer served as a transport medium only part of the way, after which the leached bitumen had to travel through the oil sand layer to reach the production end, resulting in the maintenance of injection pressure at the higher value and a larger residence time for bitumen dissolution. Visual observation of the oil sand layer supported the above theory. The packing technique for the bottom water was changed as a result.

5.8.4 Effect of Well Penetration

Runs 16 and 17 were conducted to study the effect of well penetration on bitumen recovery. Parameters such as the thickness ratio [h_b/h_w = 5.0], rate [300 ml/hr] and bottom water permeability [k_{aw} = 24 μm^2] were kept constant except for well penetration. In Run 16, the injection well was completed close to the bottom water zone - at 85% oil sand depth while the production well was completed at 34% oil sand depth. In Run 17 the depths were reversed, i.e. the production well was close to the bottom water zone - 34% oil sand depth while the injection well was at 85% oil sand depth.

The production history for Run 16 is tabulated in Table B16 and is presented in Fig. C16. The pressure profile of the run obtained was similar to that obtained for Model I. The pressure peaked at 82 kPa. The maximum effluent concentration was a mere 7% and was sustained for a very short period, after which the concentration was virtually zero. This resulted in an extremely low bitumen recovery (3.5% OBIP at 2.6 HCPV). Bitumen breakthrough was at 0.13 HCPV's injected, which was much earlier than in the previous cases.

The results for Run 17 are tabulated in Table B17 and are plotted in Fig. C17. The pressure profile is again similar to that for the previous runs except for the initial pressure drop indicated at the beginning of the run, due to a small leak, which was plugged as soon as it was detected. The cumulative bitumen recovery was 14.7% at 2.5 HCPV's solvent injected, while the maximum effluent concentration was 13%. The solvent recovery was 76%. Fig. 5.14 is a comparison of the recoveries for the two well penetrations.

An attempt was made to have identical conditions for the two runs except for the parameter to be studied which was the effect of well penetration on bitumen recovery. The bottom water layer (Run 16) was not packed as tightly as desired due to the pressure of the Neoprene diaphragm and as a result, the ratios of the thickness of the oil sand layer-to-bottom water layer were different. However, based on results of Runs 3, 4 and 6 in which the recovery was nearly the same for the ratio of heights between 4 and 7, it is concluded that the large difference in the production histories in the ultimate bitumen recoveries of the two runs - 14.7% (Run 17) vs. 3.5% (Run 16) - was a direct result of the difference in the well penetration. In both runs the overburden pressure was set at 3450 kPa.

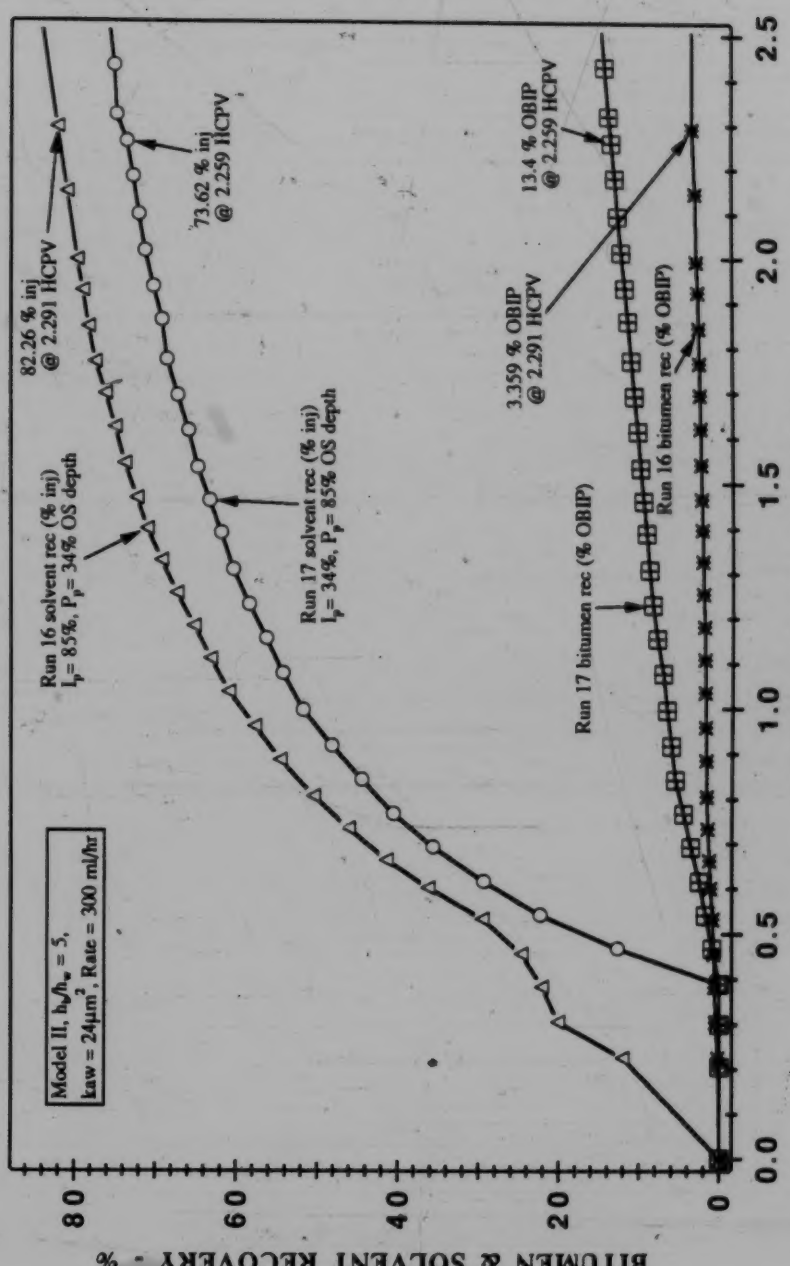


Figure 5.14: Effect of Well Penetration on Bitumen Recovery.

5.8.5 Strategy to Minimize Solvent Injection

Runs 18, 19, and 20 were part of a set of runs that explored methods of minimizing the solvent volumes injected while obtaining comparable or higher recoveries than in the case of continuous solvent injection. The strategy was as follows:

i) In Run 18, the strategy was to inject approximately 0.5 HCPV of solvent - based on results from previous runs - followed by a slug of water, size of which was determined by the water cut in the produced effluent (Water Hydrocarbon Ratio; WHCR >4). An upper limit of 0.5 HCPV was set on the water slug.

ii) Run 19 was similar to Run 18 except that a 1% (wt) aqueous solution of a surfactant, Stepanflo 80 was used instead of water.

iii) Run 20 was similar to Run 19 except a lower surfactant concentration of 0.1% was used.

Stepanflo 80 is an alkyl benzene sulfonate which has been found to be effective on Athabasca oil sands by way of lowering the IFT between the bitumen and water. The surfactant concentrations were chosen from Fig. 5.15, which is a plot of bitumen/aqueous interfacial tension behaviour, as a function of surfactant concentration. A 33 wt% solution of bitumen in synthetic crude was used in the determination of the curve. This concentration was chosen based on the maximum observed bitumen concentration in the previous runs.

Water Alternating Solvent Run

Run 18 was a solvent-alternating-water run in which a total of three slug pairs (solvent and water) were injected. The production history is tabulated in Table B18 and is plotted in Fig. C18. Note that the pressure and solvent recovery curves are virtually mirror images. During solvent injection the injection pressure increased as a result of bitumen banking. During water injection, the pressure decreased drastically due to the displacement of

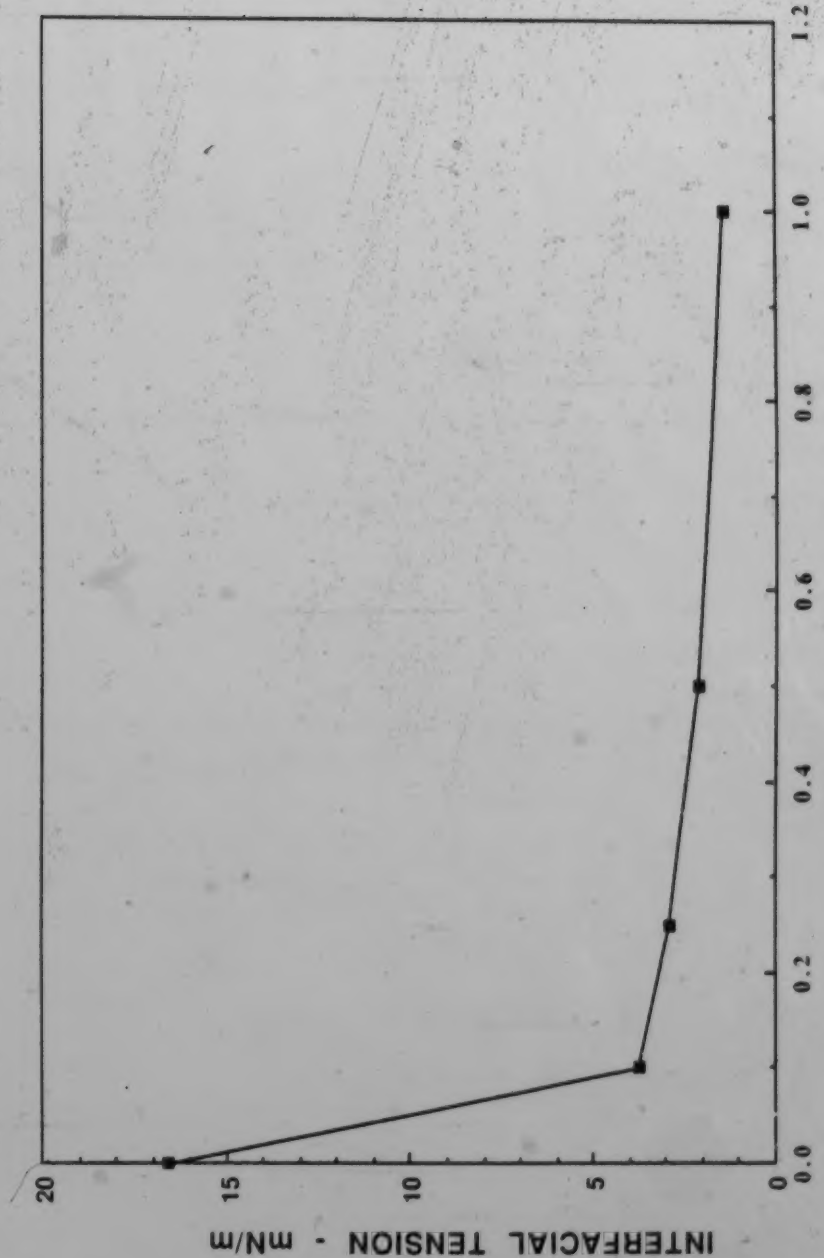


Figure 5.15: Bitumen/Aqueous IFT Behaviour, as a Function of Surfactant Concentration.

mobilized bitumen into the producer. The maximum instantaneous bitumen concentration decreased as the number of slugs increased, resulting in a slight increase in the cumulative bitumen recovery. Figure 5.16 gives a comparison of the recoveries for Runs 17, and 18 for the same amount of solvent injected.

Figure 5.17, shows that the third slug was ineffective in recovering any bitumen. Also considering the total HCPV's of solvent injected, the overall bitumen recovery was slightly lower than in the case of continuous solvent injection [Run 17], for the same amount of solvent injected. An explanation for the recovery trend is offered below. The recoveries in both runs (Run 17 and 18) for the initial solvent injection were quite similar (1.72% at 0.54 HCPV and 1.56% OBIP at 0.49 HCPV) as observed in Fig 5.16, explained by the fact that initially dissolution by leaching was the main recovery mechanism and this was the same for both runs. Recovery in the two runs started to deviate after the injection of water into the system because now diffusion was the dominating mechanism, and its effect was lessened by the introduction of water in the system. Thus, the bitumen recovery or rather the bitumen produced in the effluent in Run 18 is a result of immiscible displacement by water only. The effect is very pronounced in the third cycle, where dissolution by leaching hardly plays a part, and diffusion is inhibited by the water present in the system even when solvent injection is resumed.

Observation of the post-run core showed that the bottom water layer was dark brown in color as a result of the mobilized bitumen moving through the bottom water layer, indicating that water was not very efficient in displacing the mobilized bitumen from the bottom water zone. The oil sand layer at the interface of the two layers was of the same color as the bottom water zone. The injection side was comparatively light and loose, indicating that much of the mobilized bitumen came from this region. The production side was darker than the injection side but lighter than the middle area which in turn was slightly

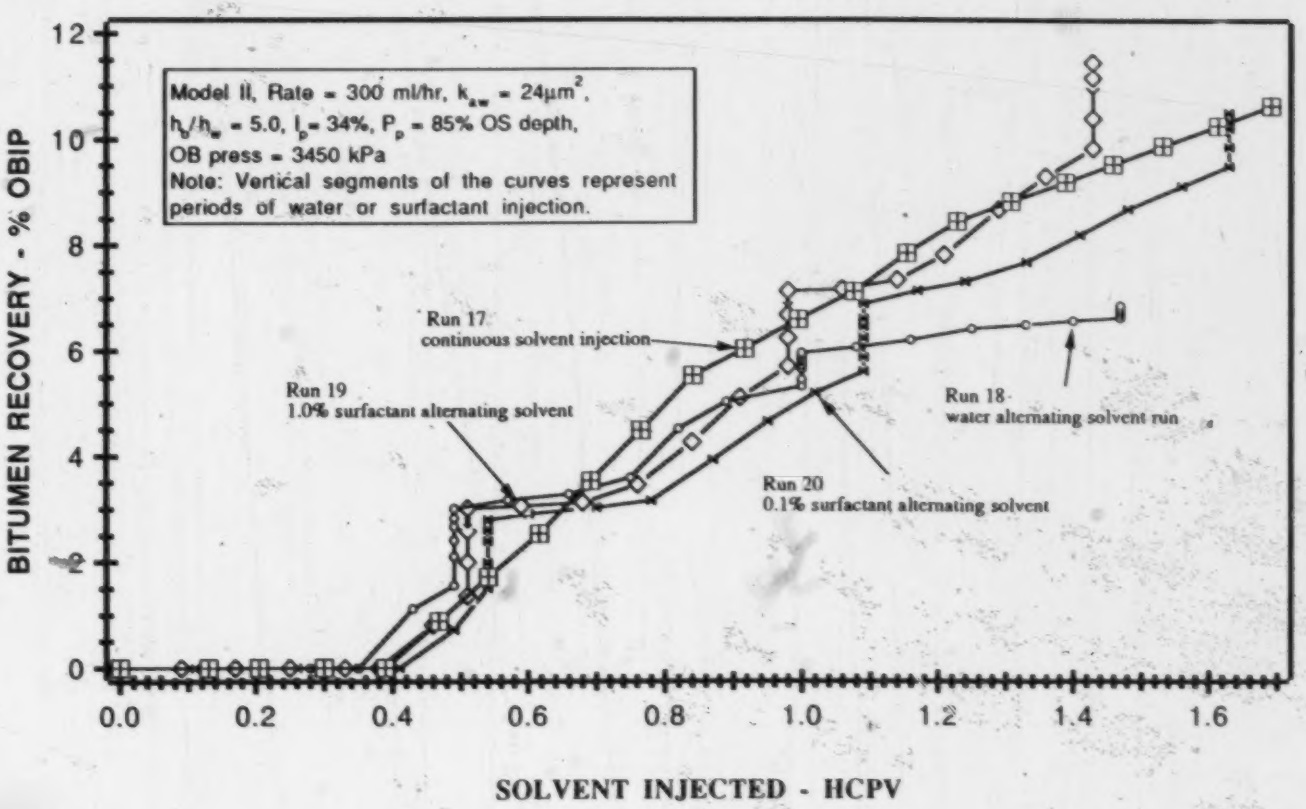


Figure 5.16: Comparison of Different Injection Strategies.

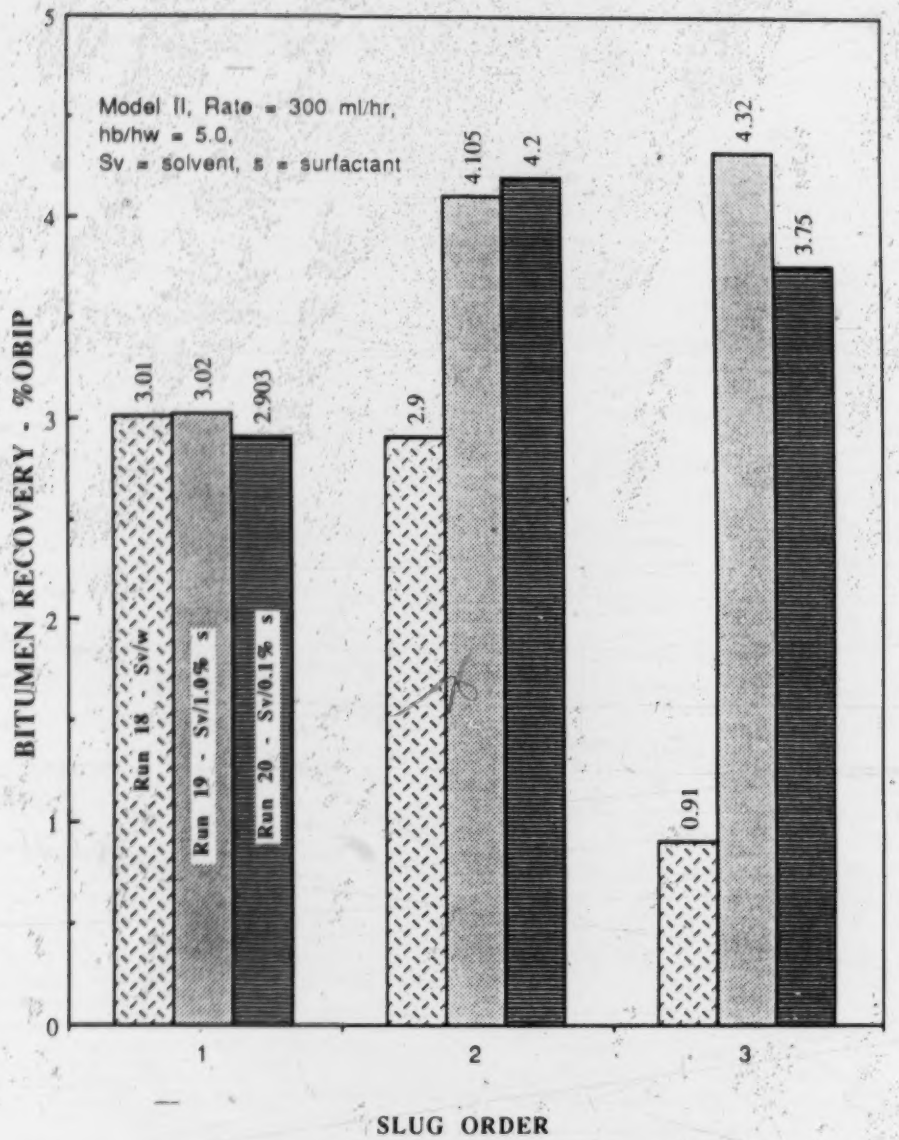


Figure 5.17: Recovery Distribution for each Injected Slug.

lighter than the original oil sand. The variations in color and the texture gave a good indication of bitumen removal. These visual observations were supported by the results from the post-test core extraction for bitumen and water content.

1.0% Surfactant Alternating Solvent Run

The next run in the series [Run 19], was a solvent/surfactant combination run. The reason for using a solvent/surfactant combination was as follows. Surfactants are known for their ability to reduce the interfacial tension between the oleic and aqueous phases, which in-turn improves the displacement efficiency of the oleic phase and may aid in bitumen leaching. It was expected that these properties would help to mobilize the bitumen from the bottom water zone and at the same time prolong the diffusion process.

Run 19 was similar to Run 18 except that a 1% surfactant solution was used instead of water. The production history is tabulated in Table B19 and is shown in Figure C19. The peak pressure increased as the number of slug sequences increased. The overall bitumen recovery (11.3%) was higher than that in Run 18 (6.8%)for the same amount of fluid injected (2.5 HCPV). The recovery was also higher than that in Run 17 (9.5%) for the same amount of solvent injected (1.4 HCPV). Another interesting feature of the run was that the instantaneous concentration did not drop drastically during surfactant injection, or even as the number of slugs increased as it did in the previous run (Run 18). The overall solvent recovery was slightly lower (71%) than in the other two runs (75.7% in Run 17 and 75.5% in Run 18). Considering the incremental bitumen recovery as a function of the number of slugs injected (Fig. 5.17), it is observed that the recovery increased as the order of the slug injection increased (3.02% for the first slug pair vs. 4.32% for the third slug pair).

Post run observation of the two layers showed that the bottom water layer had a hint of brown coloration, indicating that most of the mobilized bitumen had been transported to the production well from the bottom water layer. The oil sand layer at the interface and up to 0.3 cm into the oil sand layer, and the injection side up to 5 cm from the edge was light brown in color and loose indicating that bitumen had been removed from this region. The production side was slightly darker than the injection side but was lighter than the original sand indicating that bitumen had been leached from this region. The rest of the sand was almost as dark as the original oil sand, except that the bitumen was less viscous, indicating that some solvent had penetrated the region.

A possible explanation for the distinct behaviour of Run 19 from that of Run 18 is given below. The first slug had the same effect as in Run 18 [Fig. 5.16] which is expected, since dissolution was the major bitumen mobilizing mechanism. The pressure profile, bitumen recovery, and solvent recovery were the same. A slight deviation started to take place once water or aqueous surfactant solution was injected and was more pronounced in the second injection cycle. Water inhibited diffusion, while the surfactant on the other hand succeeded in transporting most of the mobilized bitumen as indicated by the "clean" bottom water layer. Also, it did not seem to inhibit the diffusion process and actually enhanced the recovery process. This premise is supported by the increase in incremental bitumen recovery per slug cycle.

The overall bitumen recovery for the same amount of solvent injected was higher than in the case of continuous solvent injection (11.3% vs. 9.5%). The surfactant solution was effective in transporting the mobilized bitumen from the bottom water layer. The aqueous solution in the effluent was analyzed for surfactant loss and the largest surfactant loss was observed at the start of the first slug, where the concentration in the effluent was nearly 70% that of the original surfactant solution. The losses were less severe in the following

slugs. It is felt that the initial surfactant loss was fairly significant and the initial reduction in concentration is probably due to the surfactant being adsorbed by the rock matrix.

0.1% Surfactant Alternating Solvent Run

Run 20, the last run in the series was also a combination solvent/surfactant run. Since, the idea is to use the least possible amount of surfactant, it seemed logical to use a lower concentration of surfactant and observe its effect on recovery. A concentration of 0.1% was chosen at a point were the interfacial tension stopped decreasing rapidly [Fig. 5.15], and the difference in IFT between the two concentrations (0.1% and 1.0%) was small (3.7 mN/m vs. 1.4 mN/m) expecting that the bitumen recovery would not be affected significantly by the difference.

The production history is plotted in Fig. C20 and is tabulated in Table B20. Comparing Figs C19 and C20, it is seen that the trends are very similar except for the concentration profile. In the 1.0% surfactant run the bitumen concentration remained fairly constant, even during surfactant injection, while in Run 20, it started to decrease. The increase in pressure drop was also higher in Run 19. These differences seem to indicate that the bitumen depletion was not as high as in Run 19 and the displacement of the mobilized bitumen was not as efficient. This fact was confirmed when the post run core was examined both visually and analytically. The bottom water layer was dark in color showing the presence of mobilized bitumen, unlike the bottom water layer in Run 19. Thus it would seem that the 0.1% concentration was not as efficient as the 1% solution. Figures 5.16 and 5.17 show a comparison of the cumulative recoveries and the incremental recovery per slug for the three runs.

5.9 Sources and Magnitudes of Error

In the displacement tests conducted, the effluent consisted of two phases, namely an aqueous and a hydrocarbon phase. Bitumen and solvent recoveries were calculated from the effluent volumes, which were determined by visual observation after centrifugation. The samples were collected in 50 cm^3 centrifugal tubes graduated in 2.5 cm^3 increments (± 1 cm^3 uncertainty in 50 ml). A complete run yielded at least 30 of these samples to be analyzed for hydrocarbon and aqueous phases, which draws attention to error accumulation and its effect on the final recovery. An additional source of error in reading the phase volumes was the emulsification of the phases. The volumetric balance can be evaluated by plotting the cumulative fluid injected versus cumulative production. The volumetric balance curves for selected runs are presented in Appendix C. The total error was around ± 5%.

The core was extracted and the residual bitumen and solvent concentrations were determined. A mass balance was then conducted for the runs, again the the total error was around ± 6%, and can be accounted for by the bitumen and sand loss during cleaning of the core, intrinsic errors in the determination of bitumen density, bitumen concentration in the effluent and composition of the oil sand.

6. NUMERICAL SIMULATION

The numerical simulator used for this study is a modified version of the isothermal, two-dimensional, two-phase, two-component model for a solvent-bitumen system developed previously [20]. Kaleli's[32] modifications to this simulator consisted of an improved viscosity correlation, and also representation of a bottom water zone. The modifications done in the present study included a correction in the gravity coefficient which had a significant impact on the overall results, particularly to the pressure profile. In addition, extensive comment statements were added, and the program was made more user friendly. The simulator is described briefly below.

6.1 Theoretical Development

6.1.1 Assumptions

The treatment of the problem was based upon the following assumptions:

1. Oil sand can be divided into two basic matrices: bitumen which is initially immobile due to its high viscosity, can be treated as a semi-solid, which becomes mobile upon sufficient dilution, and a sand matrix, which constitutes a rigid rock matrix.
2. The injected solvent instantaneously invades the porous medium by displacing the connate water.
3. Bitumen particles have homogeneous, isotropic diffusive properties such that solvent migration within the interior is at a molecular level. Thus, only the normal components contribute to solvent transfer into the semi-solid bitumen interior.
4. All bitumen particles are spherical for geometric simplification.
5. A critical concentration C^* determines the mobility of the solid/liquid interface. Solvent concentration is less than or equal to C^* in the semi-solid interior and greater than C^* in the liquid phase. The inter facial concentration buildup at the contact surface to the

critical is instantaneous and remains single valued for the duration of the dissolution process.

6. The liquid phase is an incompressible fluid in which the constituents propagate by both diffusive and convective transport mechanisms. The semi-solid species propagate by diffusion only.
7. Boundary layer effects are neglected so that the transition zone is a transitional layer of uniform thickness. Concentration is assumed to be linear across the transition zone, and thus solvent transfer into the semi-solid phase through the transition zone is approximated by first-order adsorption.

6.2 Simulator

The time dependent matrix porosity, ϕ_m, is the volume fraction void of sand, in which both bitumen and solvent phases coexist. The instantaneous porosity, ϕ, is the volume of the flowing liquid in which convection currents exist. The instantaneous liquid saturation, S, is the macroscopic volume of liquid in the semi-solid/liquid system.

$$S = \frac{\phi}{\phi_m}, \qquad \text{(6.1)}$$

The spherical solute particles have a uniform local size distribution and the particle number density, n_p, relates the average particle radius, r_p, to the macroscopic liquid saturation.

$$S = 1 - \frac{4\pi}{3} \frac{n_p r_p^3}{\phi_m}, \qquad \text{(6.2)}$$

The particles shrink as bitumen is desorbed, and the velocity of dissolution, $\dot{r}_p$, is given by the radial advance of contact.

$$\dot{r}_p = \frac{dr_p}{dt}, \qquad \text{(6.3)}$$

Conservation of solvent mass over the solid-solid subregion equates the rate of solvent transfer from the liquid phase, through the transition layer, δ, to the net accumulation

within the solid spheres. This yields a radial dissolution integro-differential equation for the sphere radius, r_p, as a function of the macroscopic liquid phase solvent concentration, C.

$$C^* \frac{\partial}{\partial t}\left\{ r_0 F(t) + \int_0^t \dot{r}_p(\tau) F(t-\tau) d\tau \right\} = r_p^2 \left[C\dot{r}_p + \alpha\left(C - C^*\right)\right] \quad \text{.....} \quad (6.4)$$

$$F(t) = r_p^2 \left[\frac{1}{3} - \frac{2}{\pi^2} \sum_{k=1}^{\infty} e^{-k^2 \pi^2 D_e t / r_p^2} \right] \quad \text{.....} \quad (6.5)$$

where α, is the adsorption coefficient which governs the rate of solvent adsorption across the transition zone. If fluids are moving through the porous medium, molecular diffusion may be enhanced by directional velocity dispersion. The longitudinal and transverse coefficients can be calculated by the equations below[22].

$$D_t = \frac{D_o}{F_R} + 0.0157 \sigma d_p |\vec{v}|, \quad \text{.....} \quad (6.6)$$

$$D_\ell = \frac{D_o}{F_R} + 0.5 \sigma d_p |\vec{v}| \quad \text{.....} \quad (6.7)$$

Equating the rate of solvent accumulation to the combined convective and diffusive fluxes yields the convective-diffusion-with adsorption equation given below.

$$\frac{\partial}{\partial x_i}\left(D_{ij} \frac{\partial C}{\partial x_j} - v_i C \right) = \left(\phi_m - \frac{4\pi}{3} n_p r_p^3 \right) \frac{\partial C}{\partial t} + 4\pi n_p r_p^2 \left[\alpha\left(C - C^*\right)\right] \quad \text{.....} \quad (6.8)$$

Darcy's equation is used to relate the potential gradient to the volumetric fluid flux density.

$$\vec{v} = \frac{\vec{u}_c}{\rho_s C}, \quad \text{.....} \quad (6.9)$$

$$v_i = -\frac{k_i}{\mu} \frac{\partial}{\partial x_i}(p + \rho g h), \quad \text{.....} \quad (6.10)$$

Conservation of mass equates the accumulation of fluid due to variations in concentration, to the apparent velocity giving the Darcy-Continuity equation.

$$\frac{\partial}{\partial x_i}\left\{\frac{\rho k_i}{\mu}\frac{\partial}{\partial x_i}(p+\rho g h)\right\}=\phi_m\left(1-\frac{4\pi}{3}n_p r_p^3\right)\frac{\partial p}{\partial t} \quad \ldots\ldots\ldots \quad (6.11)$$

The Kozeny-Carman equation as presented in Scheidegger[46] is used to analytically relate the component permeabilities to porosity. The bitumen-solvent viscosity is related to the liquidity determined by the solvent component viscosities and densities using Cragoe's Method[45].

6.3 Numerical Solution

Equations 6.4, 6.8 and 6.11 constitute the coupled system of non-linear equations to be solved. The approach used is described briefly. The time step is based on the incremental pore volumes of fluid injected at a constant flow rate. The space domain is partitioned into a regular mesh-centered grid. The radial dissolution equation, Eq. 6.4, is discretized using central differences for the time domain and the midpoint rule for integration. The Darcy-continuity equation, Eq. 6.11, is discretized using central differences to obtain an implicit expression for pressure. The integral form of the convective-diffusion with adsorption equation, Eq. 6.8, is spatially discretized using central differences and is time integrated with the Crank-Nicholson scheme. The Truncation Cancellation Procedure, TCP, is used for the direct solution.

The mid-point velocities and diffusion coefficients are evaluated at the mid-points from the current pressure iterate to generate values for the concentration at the next consecutive time node. A mass balance check is used to monitor the differential and cumulative errors that arise in the approximate solution to the overall scheme.

6.5 Organization of the Computer program

Figure 6.1 shows a flow chart for the simulator which is written in Fortran to simulate the concentration and saturation distributions of a two-dimensional leaching of a solid oil phase immersed in a streaming incompressible flow field bounded within a finite porous region. A listing of the computer program and sample input and output files are given in Appendix E.

6.6 Numerical Simulation Results

6.6.1 Process and Reservoir Conditions

A data set was developed to represent and to evaluate the parameter sensitivities. This data set was structured to match the experimental conditions and properties of the porous media and fluids used. Table 6.1 shows the preliminary physical data chosen for simulation. The physical dimensions of Model I were used in the simulator. Experimentally determined porosity, saturation, fluid injection rate, bitumen and the Suncor synthetic crude densities and viscosities were used. The absolute permeability of the sand matrix was determined using the Kozeny Carman[46] equation. The formation resistance factor, inhomogeneity factor, longitudinal and transverse parameter coefficients were obtained from Perkins and Johnston[22].

The initial solid diffusivity was calculated using the Wilke and Chang estimation method[47] and compared to literature values[47,48] Actual values for the system were not available but the calculated value was of the same order of magnitude as that for other similar systems. The molecular diffusivity was estimated using Wilke and Chang estimation method[47], the molecular weight of the solvent was determined using Cragoe's equation[49]. Literature values[50] were used for the particle diameter and bitumen molecular weight. The initial sphere radius was estimated using the bitumen content in the oil sand. The mass transfer

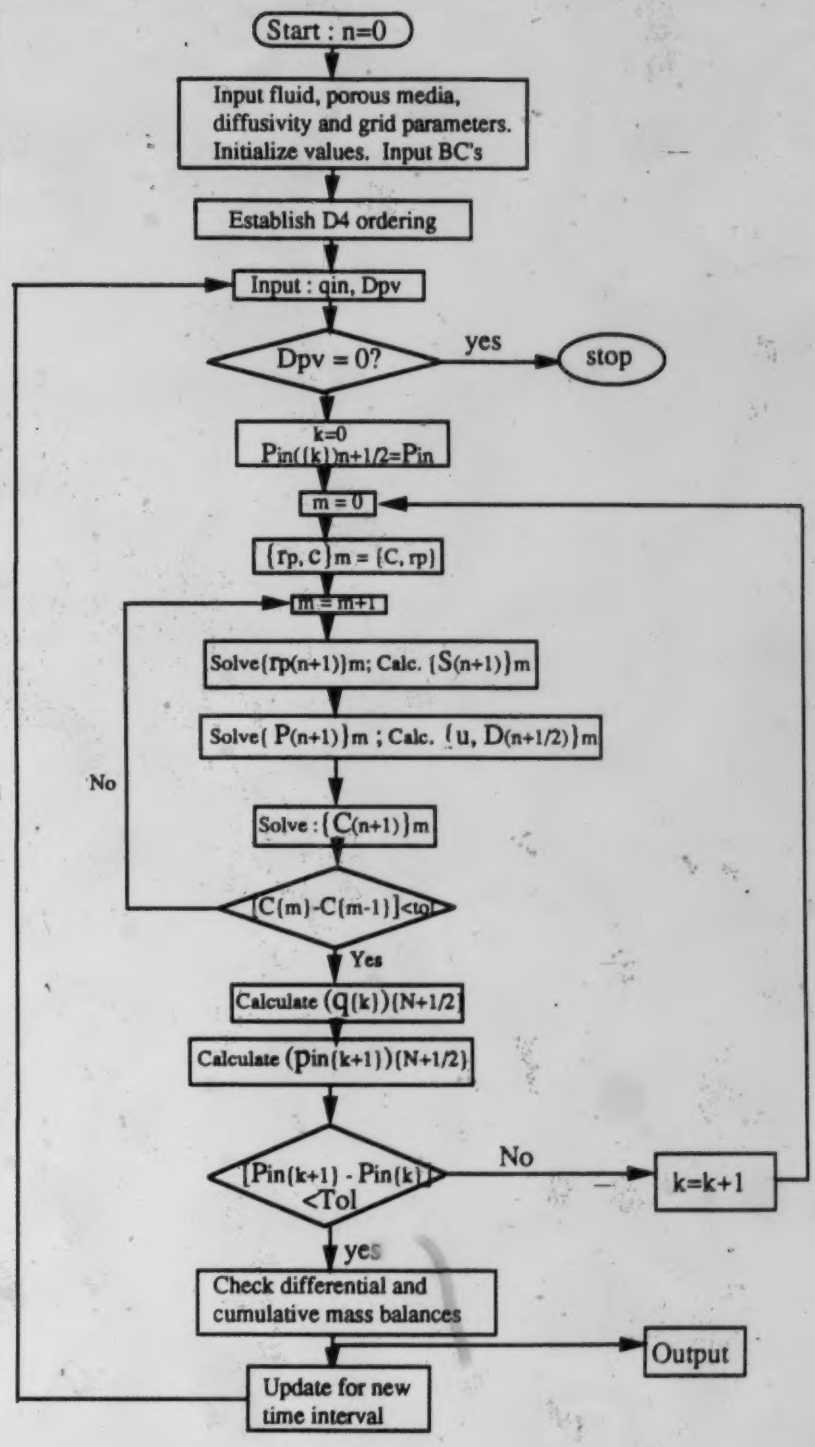


Figure 6.1 : Flow Chart for Computer Program.

Table 6.1

Simulation Physical Properties - Homogeneous Pack

Physical Model Dimensions

Length = 60 cm
Width* = 3.75 cm
Depth* = 6.25 cm
* The depth and width are interchanged in the actual simulator since the 2-d directions used in the simulator are in the x and z directions.

Fluid Properties at 23 °C

Inj. Rate = 0.0833 ml/s
Bitumen Density = 1.03 g/ml.
Bitumen Viscosity = 191000 mPa.s
Solvent Density = 0.8665 g/ml
Solvent Viscosity = 4.6 mPa.s

Porous Media

Oil Sand zone

Matrix Porosity, ϕ, = 0.39
$k_x = k_y = 19\ \mu m^2$
Oil sand Thickness = 6.25 cm

Parameters

Molecular Diffusivity [D_o] = 5.E-7 cm^2/s
Solid Diffusivity [D_s] = 7.0E-9 cm^2/s
Particle Diameter [d_p] = 0.1 cm
Initial Sphere Radius [r_o] = 0.03 cm
Formation Resistance Factor [F_R] = 4; Inhomogeneity Factor [σ] **= 3.5
Critical Concentration [C^*] = 0.25
Instantaneous Liquid Saturation [S_o] = 0.25
Mass Transfer Coefficient [α] =5.0E-7 cm/s
Longitudinal Parameter Coefficient [α_l] = 0.5
Transverse Parameter Coefficient [α_t] = 0.0157

coefficient and critical concentration were two parameters that were obtained by history matching, although the initial values were the same as those used previously[32].

6.6.2 Parametric Sensitivities

An attempt was made to evaluate qualitatively the sensitivity of the leaching model to various parameters. The parameters that were investigated and their effect on the cumulative OBIP[%] is described below:

a) Critical concentration was one of the most sensitive parameters in the simulator. Increasing the critical concentration, C*, resulted in a decrease in bitumen recovery and an increase in solvent recovery. The incremental bitumen recovery peaked at a lower concentration and this peak value occurred at a lower value of HCPV's solvent injected.

b) Recovery was also sensitive to the adsorption factor, α. Increasing α, resulted in a broader bitumen recovery peak indicating increased incremental bitumen recovery and solvent recovery.

c) Both liquid and solid diffusivities influenced the pressure distribution but did not change the recovery profiles appreciably. However, it is possible that these parameters may have a larger effect with other parameter combinations.

d) The longitudinal and transverse parameter coefficients did not affect the results perceptibly.

e) Results were relatively insensitive to the oil sand absolute permeability in the case of a homogeneous pack in the range considered (Fig. 6.2), but there was considerable sensitivity to absolute permeability when bottom water was present. Two cases were studied and are presented in Figure 6.3.

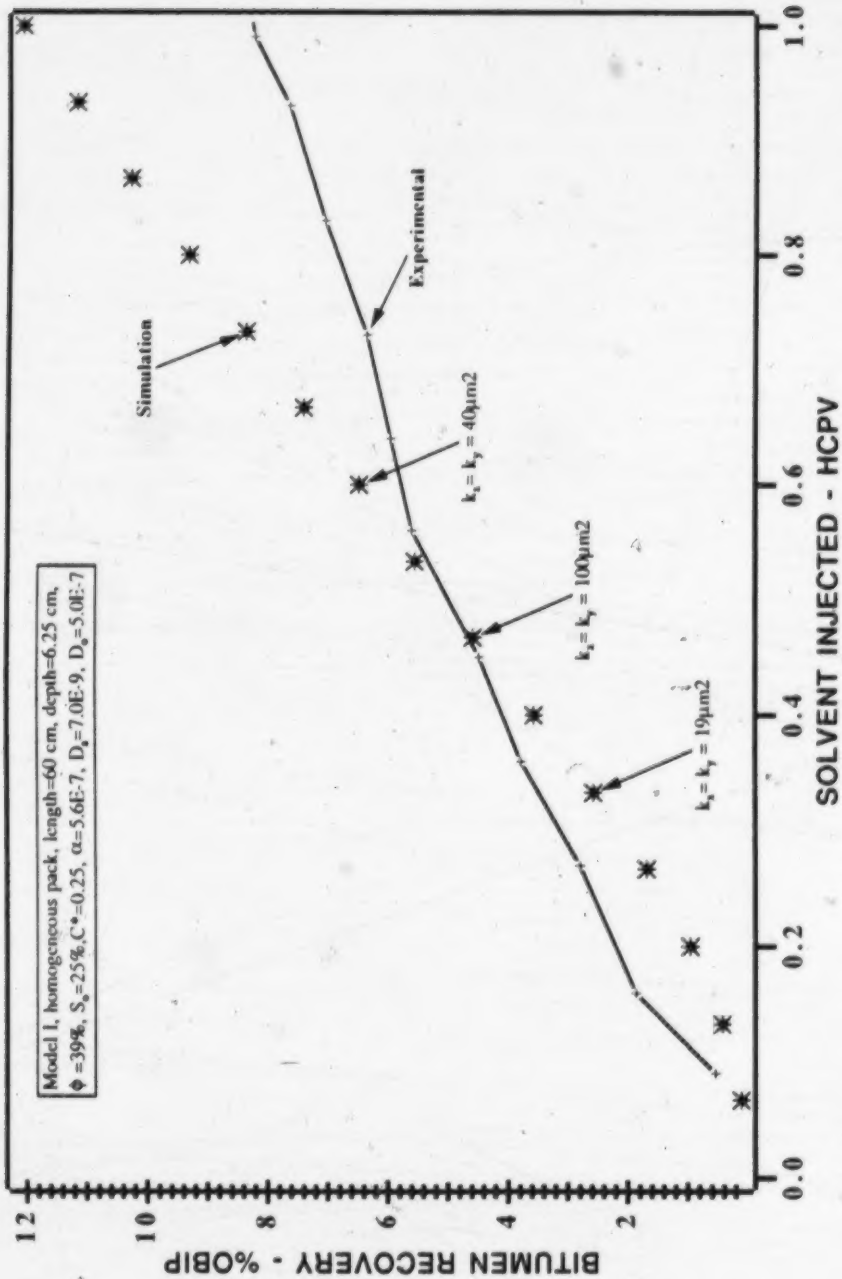


Figure 6.2: Effect of Absolute Oil Sand Permeability on Bitumen Recovery in a Homogeneous Pack.

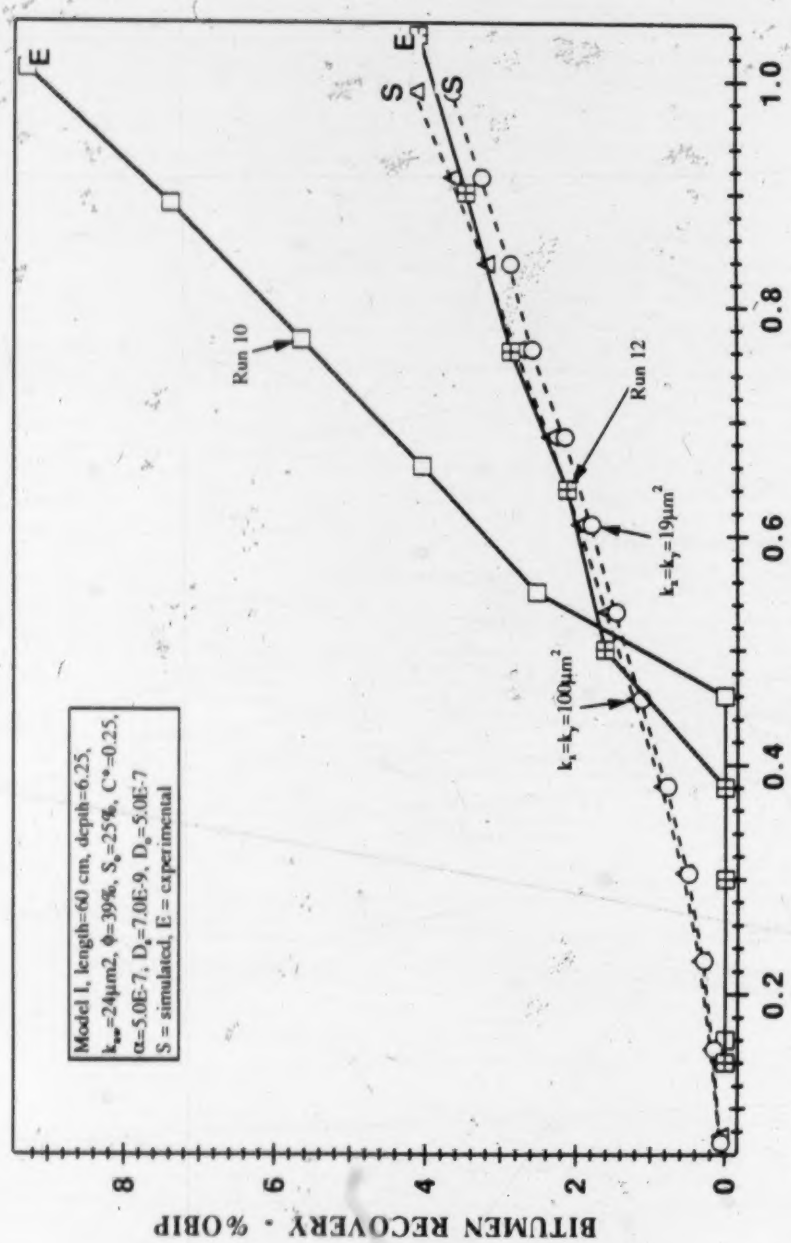


Figure 6.3: Effect of Oil Sand Zone Permeability on Bitumen Recovery in the Presence of Bottom Water - $k_{a,w}$=24μm^2.

f) Decreasing the particle size increased the rate of the leaching process, resulting in higher pressures due to bitumen banking which decreased drastically as the bitumen was produced. Since the bitumen concentration in the oil sand is taken into account in the calculation of the radius of the sphere the assumption that bitumen may be modelled as a sphere instead of the concentric particle (bitumen coating sand) may have a big effect on the modelling.

6.7 Features of Simulation Runs

Model I, with the physical properties listed in Table 6.2 was chosen as a basis for simulation. The principal variable quantity in the simulation runs was the bottom water permeability, although the oil sand permeability was varied to confirm the trend.

6.7.1 Bottom Water Runs: $k_x=k_y=19\ \mu m^2$

The simulation conditions listed in Table 6.2 were used for the bottom water runs. These conditions were based on the history match obtained using the experimental data for the homogeneous run - Run 1 (Fig. 6.2). Three different bottom water permeabilities (2, 24 and 200 μm^2) were simulated using an oil sand permeability of 19 μm^2 which was calculated from Run 1 data. The simulation results qualitatively matched the experimental results of Runs 9 (2μm^2), 10 (24μm^2), and 11 (200μm^2) as seen in Fig. 6.4. The trend showed that bitumen recovery decreased as the bottom water permeability increased, however, it was not intended to match the results quantitatively by adjusting the various parameters. Also, note that the simulation results for the 24 and 200 μm^2 runs are very similar and therefore there could be some doubt as to the validity of the results for bottom water zone permeabilities in this range.

Table 6.2

Simulation Physical Properties
Bottom Water Runs

Physical Model Dimensions

Length = 60 cm
Width* = 3.75 cm
Depth* = 6.25 cm
* The depth and width are interchanged in the actual simulator since the 2-d directions used in the simulator are in the x and z directions.

Fluid Properties at 296 K

Inj. Rate = 0.0833 ml/s
Bitumen Density = 1.03 g/ml.
Bitumen Viscosity = 191000 mPa.s
Solvent Density = 0.8665 g/ml
Solvent Viscosity = 4.6 mPa.s

Porous Media

Oil Sand zone

Matrix Porosity, ϕ, = 0.39
Bitumen Layer Thickness = 5.25 cm

Bottom Water Zone
Bottom Water thickness = 1.0 cm

Parameters

Molecular Diffusivity [D_o] = 5.E-7 cm^2/s
Solid Diffusivity [D_s] = 7.0E-9 cm^2/s
Particle diameter[d_p] = 0.1 cm
Initial Sphere Radius = 0.03 cm
Formation Resistance Factor [F_R] = 4; Inhomogeneity Factor [σ] = 3.5
Critical Concentration [C^*] = 0.25
Instantaneous Liquid Saturation [S_o] = 0.25
Mass Transfer Coefficient [α] =5.0E-7 cm/s
Longitudinal Parameter Coefficient [α_l] = 0.5
Transverse Parameter Coefficient [α_t] = 0.0157

Variables

$k_x = k_y = 19\ \mu m^2$	$k_x = k_y = 100\ \mu m^2$
$k_{aw} = 2\ \mu m^2$	$k_{aw} = 2\ \mu m^2$
$k_{aw} = 24\ \mu m^2$	$k_{aw} = 24\ \mu m^2$
$k_{aw} = 200\ \mu m^2$	$k_{aw} = 200\ \mu m^2$

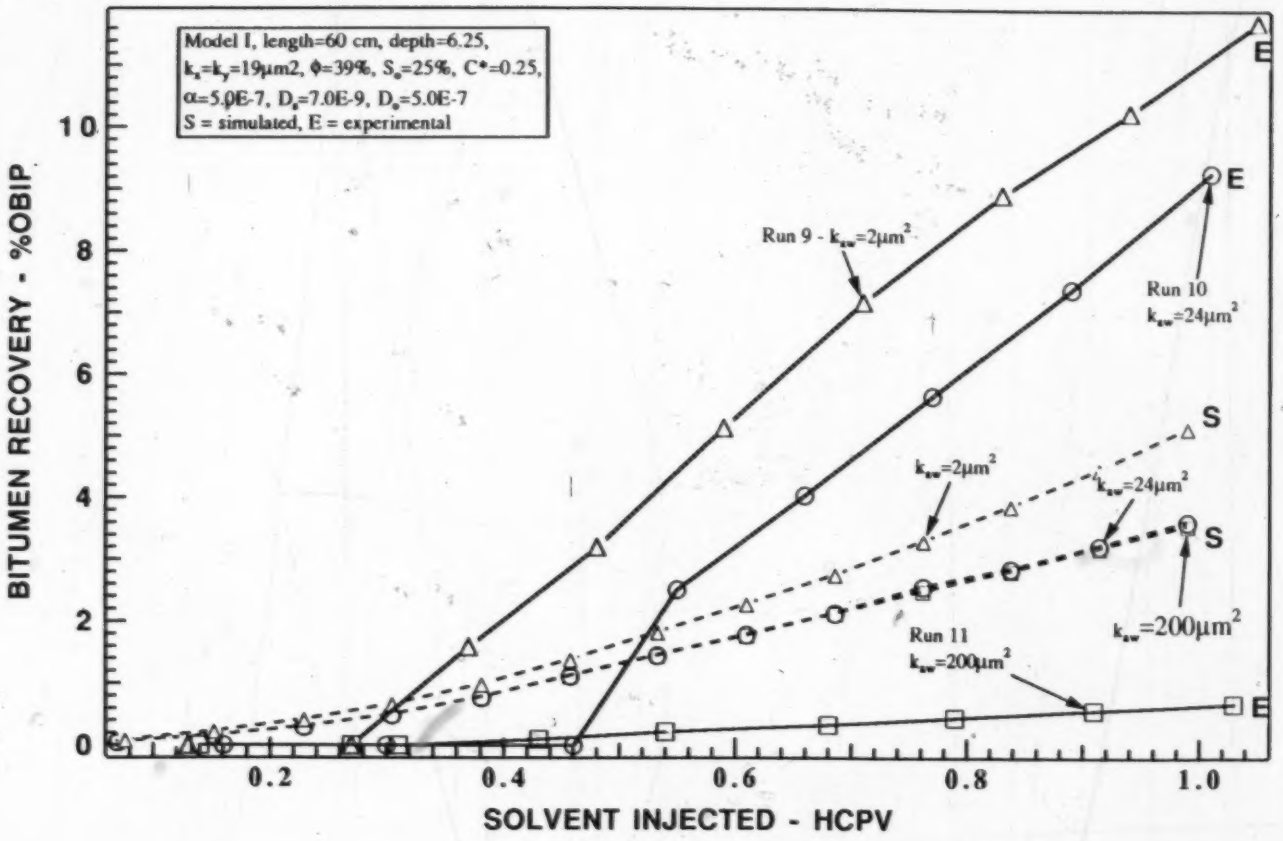


Figure 6.4: Effect of Bottom Water Zone Permeability - $k_x=k_y$ = 19μm² .

6.7.2 Bottom Water Runs: $k_x=k_y=100\ \mu m^2$

The next simulation set was run in order to confirm the recovery trend for the bottom water permeabilities, and to investigate if the oil sand permeability had an effect on bitumen recovery in the presence of bottom water. The unusually high bitumen recoveries in Runs 9 to 11, were attributed to a loose oil sand pack in the vicinity of the second injection well which could have resulted in an oil sand absolute permeability greater than the calculated value of 19. To test out this conjecture the oil sand absolute permeability was changed to 100 μm^2 and the three bottom water permeabilities were rerun.

A recovery trend similar to the experimental runs was observed as seen in Fig. 6.5, i.e. the lower bottom water permeability ($2\mu m^2$) had the highest bitumen recovery as in the experimental run, (Run 9) while the higher bottom water permeability run had the lowest.

6.7.3 Effect of Oil Sand Permeability on Bottom Water Runs

The results of the simulation runs (kx=ky=19, and $100\mu m^2$) with a bottom water permeability of 24 μm^2 are shown in Fig. 6.3. It can be seen that the oil sand permeability has an effect on bitumen recovery. A higher absolute oil sand permeability results in higher recoveries in the presence of bottom water. The bitumen recoveries for experimental Runs 10 and 12 both of which had a bottom water zone permeability of 24 μm^2 are also shown in Fig. 6.3. As seen in the figure a very good match was obtained for Run 12 recovery.

6.8 Discussion

The simulator is a useful tool for understanding the effect of some of the parameters that might affect recovery and also for observing the saturation profiles during the displacement process. For example, visual examination of the sand pack showed that most of the produced bitumen came from the injection and production ends of the model, as well as the

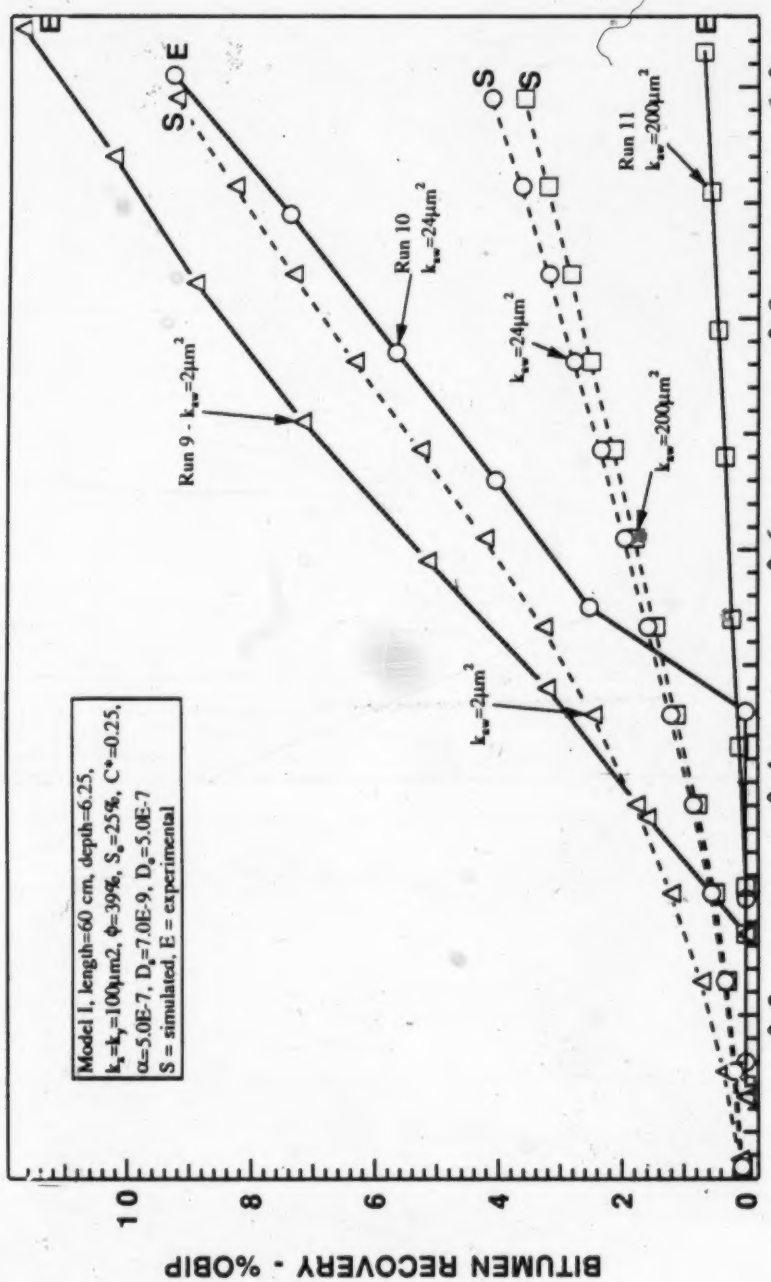


Figure 6.5: Effect of Bottom Water Zone Permeability - $k_x=k_y = 100\mu m^2$.

layer adjacent to the bottom water. This phenomenon was also observed in the simulated runs, as seen from the computed bitumen saturations.

The simulated solvent concentration is based upon the assumption that the solvent is present everywhere right from the start. As a result while the amounts of bitumen leached are meaningful, solvent concentrations are not, and were therefore not plotted. It was possible to match the bottom water pressures fairly well. The pressure drop increased as the bottom water permeability decreased.

It can be concluded that the present numerical simulator is useful for gaining insight into the parameters that might affect recovery and also for determining the mechanisms to some extent, but the results are only as reliable as the input data.

6.9 Simulator Limitations

It was found that the simulator could predict the cumulative bitumen recovery and pressures fairly well up to 1 HCPV solvent injected after which it predicted higher recoveries for the homogeneous pack run. In the physical experiments, recovery decreased significantly after the injection of one HCPV of solvent as the dissolution process by leaching was damped due to solvent chanelling. The simulator on the other hand did not simulate this phenomenon and continued to leach out bitumen.

An initial liquid continuity is required for the simulator to function properly. This assumption fails to predict the leaching that is initiated from the time of solvent injection, and thus the predicted bitumen breakthrough may not match the experimentally observed value.

The simulator assumes that the rock matrix is fixed, which is a reasonable assumption, but it is possible that once the bitumen is leached from a section the extracted sand may move

with the bottom water zone. Movement of fines is beyond the scope of the present simulation.

7. CONCLUSIONS

The present research examined the role of bottom water for bitumen mobilization. In this study the effect of different injection strategies as well as bottom water thickness and permeability on bitumen recovery was examined. Based on the results of experiments in two models and many numerical simulations, the following conclusions are reached:

1. Bottom water thickness has an effect on the overall bitumen recovery. A thick bottom water zone leads to solvent dissipation and comparatively low recoveries, while a thinner zone leads to reduced solvent loss and higher recoveries. It was found experimentally that the recoveries did not vary significantly for oil sand-to-bottom water thickness ratios, h_b/h_w, between 4 and 7.

2. Considering oil sand-to-bottom water thickness ratio > 4.0, it was found that a lower injection rate resulted in higher recoveries by allowing more time for diffusion. Shutting in the injection and production wells for a short period was also beneficial for the same reason, i.e. an increase in residence time resulted in higher recovery in view of increased transverse diffusion.

3. Permeability of the bottom water zone plays an important role in the ultimate bitumen recovery. Recovery did not vary significantly for bottom water zones with permeabilities between 2 and 24 μm^2; however, when the permeability was increased to 200μm^2, recovery deteriorated. As a result, reducing bottom water zone permeability may be one way of increasing the ultimate bitumen recovery.

4. The use of a second injection point, which is in effect equivalent to reducing the distance between the injector and producer, resulted in a slight increase in bitumen recovery. This effect was more pronounced in the high bottom water permeability run

indicating that reducing the well interval may be beneficial in high bottom water permeability zones.

5. The effect of well penetration is significant. A better strategy for increasing recovery is to place the injection well away from the bottom water layer and the production well fairly close to the same.

6. Model II was successful in improving pack properties by allowing for better control in the ratio of the heights of the two zones and well placement. It also reduced solvent channelling and override through the application of overburden pressure, thus resulting in a more efficient recovery process.

7. The numerical simulator was able to predict recovery trends for the different bottom water zone permeabilities qualitatively; however, it was not possible to match the recoveries for the runs considered quantitatively without adjusting various parameters. Based on the simulation results it would seem that the ratio of the permeabilities of the two zones is a significant factor in bitumen recovery. The simulator is a useful tool for understanding the effect of different parameters on bitumen recovery and for observing the saturation profiles during displacement.

8. RECOMMENDATIONS

The following recommendations are made for future studies to enhance the work already done:

1. The possibility of blocking off very thick bottom water zones on the efficiency of the recovery process should be studied.

2. A combination of solvent and surfactant injection appears promising and further consideration should be given to this technique. For example, the effect of solvent/surfactant slug size and concentration on bitumen recovery should be investigated further. It is also suggested that better methods of analyzing surfactant in both the aqueous and organic layers be examined.

3. Further experimental and/or numerical studies should be conducted on the effects of bottom water thickness, permeability and well penetration o pinpoint the transition stage at which recovery starts to deteriorate.

4. Certain modifications to the current numerical simulator are recommended. The changes listed below include changes to both the main program and to the data input:
   a) The critical concentration and adsorption coefficient are significant parameters in the simulation and the use of experimentally determined values for the synthetic crude-bitumen system is recommended.
   b) The simulation model does not assume a concentric particle, i.e. a sand particle coated with bitumen, instead it assumes spherical bitumen pellets confined to the pores. This assumption may not be entirely accurate and alternatives should be explored.

c) Assumption of initial liquid continuity, does not accurately represent breakthrough conditions and if possible should be modified.

d) The current solution scheme requires prohibitive computing time and more efficient solution schemes should be investigated.

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APPENDIX A

MATERIAL AND EQUIPMENT SUPPLIERS FOR EXPERIMENTAL WORK

Item	Supplier
Air impact wrench	Princess Auto Ltd. 11260 - 163 Street Edmonton, Alberta
Whitey Valves Swagelok Fittings 316 SS Mesh Strainer Element 40 µm Mesh Construction	Edmonton Valve & Fitting Ltd. 4503 - 93 Street Edmonton, Alberta T6E 5S9
Neoprene Sheet	Continental Petroleum Rubber 9725 - 62 Avenue Edmonton, Alberta T6E 0E4
Glass Beads Sizes 3, 8, 13	Rotair Industries Ltd. 1040 - 78 Avenue Edmonton, Alberta
Heise Gauge Labtech Notebook v 5	Dycor Industrial Research Ltd. #139 17303 - 102 Avenue Edmonton, Alberta T5 S 1J8
DAS 8 Data Aquisition and control interface board Exp - 16 Expansion Interface	MetraByte Corporation 440 Myles Standish Blvd. Taunton, MA 02780
ISCO LC-5000 Syringe Pump	Technical Marketing Associates Ltd. 6620 Kitimat Road, Unit 6 Mississauga, Ontario L5N 2B8
Perkin Elmer Infrared Demountable Sealed Cell	The Perkin Elmer Corporation 1350 Kootenay Street Vancouver V5K 4R1 1-800-663-7971
Oil Sand from Suncor's open mining site. Ft. McMurray Suncor Synthetic Crude	Alberta Research Council P.O. Box 8330 Station F Edmonton, Alberta T6H 5X2
Sample Vials Toluene Calcium Chloride Methylene Chloride Rotavapor Evaporator	Fisher Scientific Ltd. 10720 - 178 Street Edmonton, Alberta
Stepanflo 80	Stepan Company Northfield, Illonois, 60093, USA 1-416-624-7618 (Mississauga, Ontario)

APPENDIX B
PRODUCTION HISTORY OF ALL RUNS IN TABULATED FORM

TABLE B1

PRODUCTION HISTORY FOR RUN 1- Homogeneous Pack Run
[Model I, Continuous Solvent Injection;CSI]

Porosity = 39.1%
Bitumen saturation = 75.1%
keff to water = 0.2µm2

Wt. sand pack = 2832.0 g
Wt. glass bead pack = N/A
Bitumen in place = 435.0 g

Rate = 300 ml/hr
BT Volume = 32.5ml
BT pressure = 41.0kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
0	0.0	0.0	0.0	0.0	—	—	0.00	0.00	0.00	0.00
1	38.0	38.0	10.0	23.0	12.2	3.3	0.54	20.26	35.20	0.09
2	70.0	44.0	42.5	13.0	0.3	6.7	1.83	63.82	20.00	0.16
3	115.0	46.5	45.2	9.0	0.3	10.1	2.77	74.61	15.20	0.27
4	155.0	42.8	42.0	10.0	0.2	9.0	3.75	79.75	11.70	0.36
5	195.0	44.0	43.2	7.0	0.3	13.3	4.46	83.99	10.30	0.45
6	239.0	46.5	46.0	11.0	0.1	8.1	5.64	85.66	9.00	0.56
7	275.0	39.0	38.5	4.0	0.3	24.0	6.00	87.88	8.30	0.64
8	315.0	43.5	43.0	4.0	0.3	24.0	6.40	89.83	7.60	0.73
9	357.0	43.5	43.5	7.0	0.0	13.3	7.11	90.59	6.90	0.83
10	397.0	42.5	42.0	6.0	0.2	15.7	7.70	91.41	6.90	0.93
11	425.0	32.3	32.0	8.0	0.1	11.5	8.30	92.31	6.90	0.99
12	425.0	50.0	48.0	5.0	0.8	19.0	8.86	103.04	6.90	0.99
13	515.0	43.0	43.0	2.0	0.0	49.0	9.06	93.22	4.10	1.20
14	552.0	41.5	41.0	3.0	0.4	32.3	9.34	94.18	4.80	1.29
15	580.0	48.7	48.0	2.0	0.7	49.0	9.57	97.74	4.80	1.35
16	630.0	44.3	44.0	2.0	0.3	49.0	9.77	96.83	4.10	1.47
17	845.0	209.0	207.0	4.0	0.2	24.0	11.70	95.71	4.10	1.97

TABLE B1 (CONTINUED)

PRODUCTION HISTORY FOR RUN 1- Homogeneous Pack Run
[Model I, Continuous Solvent Injection;CSI]

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
18	1075.0	226.0	224.0	3.0	0.3	32.3	13.27	95.44	4.10	2.51
19	1275.0	208.0	207.0	3.0	0.2	32.3	14.72	96.22	4.10	2.97

TABLE B2

PRODUCTION HISTORY FOR RUN 2- Homogeneous Pack Run
[Model I, CSI]

Porosity = 38.0%
Bitumen saturation = 75.6%
keff to water = 0.2µm2

Wt. sand pack = 2742.0 g
Wt. glass bead pack = N/A
Bitumen in place = 435 g

Rate = 300 ml/hr
BT Volume = 32.5ml
BT pressure = 41.0kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
0	0.0	0.0	0.0	0.0	—	—	0.00	0.00	0.00	0.00
1	14.0	14.0	0.0	0.0	—	—	0.00	0.00	134.00	0.03
2	64.0	50.0	48.5	22.0	0.1	0.0	2.55	59.11	96.50	0.15
3	114.0	50.0	49.5	22.0	0.0	3.5	5.14	67.05	58.60	0.27
4	164.0	50.0	50.0	22.0	0.0	3.5	7.77	70.39	44.80	0.39
5	214.0	50.0	50.0	8.0	0.0	9.8	8.72	75.44	34.50	0.51
6	264.0	50.0	50.0	6.0	0.0	15.3	9.44	78.95	27.60	0.63
7	314.0	50.0	50.0	5.0	0.0	18.8	10.04	81.51	24.10	0.75
8	364.0	50.0	50.0	2.0	0.0	47.5	10.27	83.77	22.00	0.87
9	414.0	50.0	50.0	2.0	0.0	49.0	10.51	85.49	20.70	0.99
10	464.0	50.0	50.0	2.0	0.0	49.0	10.75	86.84	20.70	1.11
11	514.0	50.0	50.0	2.0	0.0	49.0	10.99	87.93	20.70	1.23
12	564.0	50.0	50.0	0.0	—	—	10.99	89.00	20.70	1.35
13	614.0	50.0	50.0	0.0	—	—	10.99	89.89	20.70	1.47
14	664.0	50.0	50.0	0.0	—	—	10.99	90.65	19.30	1.58
15	714.0	50.0	50.0	0.0	—	—	10.99	91.31	18.60	1.70
16	764.0	50.0	50.0	0.0	—	—	10.99	91.88	17.20	1.82
17	814.0	50.0	50.0	0.0	—	—	10.99	92.38	17.20	1.94
18	914.0	100.0	100.0	3	—	16.7	11.71	92.88	15.80	2.18

TABLE B3

PRODUCTION HISTORY FOR RUN 3 - Effect of Bottom Water Thickness
[Model I, CSI, hb/hw=4.2, kaw=24μm2]

Porosity = 38.6%
Bitumen saturation = 62.6%
keff to water = 1.7μm2

Wt. sand pack = 2322.8 g
Wt. glass bead pack = 420.3g
Bitumen in place = 357.7 g

Rate = 300 ml/hr
BT Volume = 114.0 ml
BT pressure = 35.9kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	48.0	49.5	0.0	0.0	—	0.0	0.00	0.00	24.50	0.14
2	96.0	49.0	0.0	0.0	—	0.0	0.00	0.00	33.10	0.27
3	114.0	19.0	7.5	9.0	17.0	35.7	0.19	5.99	35.90	0.32
4	153.0	42.0	40.0	9.0	0.6	35.7	1.21	28.25	33.80	0.43
5	192.0	40.0	38.0	6.0	0.9	55.3	1.86	41.12	33.40	0.54
6	231.0	40.5	39.5	6.0	0.4	55.3	2.53	50.25	33.70	0.65
7	274.0	42.5	40.5	11.0	0.4	28.5	3.79	55.52	29.90	0.78
8	313.0	41.0	40.0	3.0	0.8	114.1	4.13	61.00	28.80	0.89
9	352.0	40.5	40.0	3.0	0.4	114.1	4.47	65.26	29.10	1.00
10	390.0	42.0	40.0	3.0	1.7	114.1	4.81	68.85	28.80	1.10
11	433.0	43.0	41.0	3.0	1.6	114.1	5.16	71.20	28.40	1.23
12	472.0	42.0	39.0	4.0	1.9	84.7	5.60	73.25	28.40	1.34
13	513.0	40.0	36.0	2.0	5.6	172.9	5.81	74.27	27.80	1.45
14	550.0	42.0	39.0	2.0	3.8	172.9	6.03	76.22	27.40	1.56
15	589.0	42.5	40.5	1.0	4.9	349.2	6.14	77.98	27.30	1.67
16	628.0	40.0	38.0	1.0	5.3	349.2	6.25	79.13	27.10	1.78
17	668.0	40.0	38.0	1.0	5.3	349.2	6.36	80.02	27.30	1.89
18	706.0	42.0	40.0	2.0	2.5	172.9	6.59	81.27	26.90	2.00
19	746.0	40.0	37.0	3.0	2.7	114.1	6.90	81.72	26.60	2.11

TABLE B3 (CONTINUED)

PRODUCTION HISTORY FOR RUN 3 - Effect of Bottom Water Thickness
[Model I, CSI, hb/hw=4.2, kaw=24μm2]

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
20	786.0	42.0	41.0	3.0	0.8	114.1	7.25	82.62	26.20	2.23
21	823.0	42.0	40.0	2.0	2.5	172.9	7.48	83.67	25.80	2.33
22	863.0	41.0	40.0	3.0	0.8	114.1	7.82	84.29	25.50	2.44
23	880.0	42.0	41.0	2.0	1 2	172.9	8.05	87.23	15.90	2.49
24	903.0	44.5	44.0	1.0	1.1	349.2	8.17	89.83	24.60	2.56
25	943.0	46.0	45.0	7.0	0.3	46.9	9.07	90.46	24.40	2.67
26	1028.0	41.0	39.5	3.0	1.3	114.1	9.40	86.71	23.80	2.91
27	1073.0	45.0	44.0	2.0	1.1	172.9	9.65	87.09	23.90	3.04
28	1108.0	39.5	39.5	1.0	0.0	349.2	9.76	87.87	23.70	3.14
29	1150.0	45.5	45.5	2.0	0.0	172.9	10.02	88.53	23.40	3.26

TABLE B4

PRODUCTION HISTORY FOR RUN 4 - Effect of Bottom Water Thickness
[Model I, CSI, hb/hw=6.8, kaw=24μm2]

Porosity = 39.7%
Bitumen saturation = 63.4%
keff to water = 3.4μm2

Wt. sand pack = 2432.0 g
Wt. glass bead pack = 291.3g
Bitumen in place = 373.3 g

Rate = 300 ml/hr
BT Volume = 55.5 ml
BT pressure = 36.3kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	53.0	49.0	0.0	0.0	—	0.0	0.00	0.00	36.30	0.14
2	93.0	43.0	20.0	29.0	4.0	2.4	1.57	15.27	22.30	0.25
3	133.0	42.0	34.8	9.0	2.6	10.1	2.40	33.94	18.90	0.36
4	175.0	44.0	39.0	7.0	1.8	13.3	3.14	46.52	17.30	0.47
5	215.0	42.5	40.5	4.0	1.2	24.0	3.58	55.95	16.00	0.58
6	257.0	42.0	39.0	2.0	3.8	49.0	3.79	61.68	15.20	0.69
7	296.0	42.0	40.0	2.0	2.5	49.0	4.00	66.79	14.60	0.80
8	338.0	43.0	42.0	4.0	0.6	24.0	4.46	70.42	14.20	0.91
9	381.0	46.0	44.5	0.0	—	—	4.46	74.15	13.90	1.03
10	421.0	40.3	40.0	1.0	0.7	99.0	4.57	76.52	13.80	1.14
11	460.0	40.0	39.0	4.0	0.6	24.0	4.99	78.17	13.70	1.24
12	502.0	44.5	42.0	1.0	6.0	99.0	5.10	79.91	13.50	1.36
13	540.0	41.5	40.0	3.0	1.3	32.3	5.43	81.47	13.70	1.46
14	591.0	54.0	52.0	2.0	1.9	49.0	5.71	83.06	13.70	1.60
15	630.0	41.0	39.0	2.0	2.6	49.0	5.92	83.99	12.80	1.70
16	665.0	37.0	37.0	1.0	0.0	99.0	6.02	85.08	12.40	1.80
17	702.0	41.5	41.5	1.0	0.0	99.0	6.13	86.45	12.40	1.90
18	737.0	44.5	42.0	3.0	2.0	32.3	6.48	87.87	12.40	1.99
19	788.0	42.0	40.5	1.0	3.7	99.0	6.58	87.27	12.30	2.13

TABLE B4 (CONTINUED)

PRODUCTION HISTORY FOR RUN 4 - Effect of Bottom Water Thickness
[Model I, CSI, hb/hw=6.8, kaw=24μm2]

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
20	828.0	43.0	40.5	0.0	—	—	6.58	87.94	12.10	2.24
21	868.0	42.5	42.0	4.0	0.3	24.0	7.04	88.54	12.10	2.35
22	905.0	42.5	40.0	1.0	6.3	99.0	7.15	89.29	12.10	2.45
23	947.0	39.5	37.0	1.0	6.8	99.0	7.25	89.20	11.70	2.56
24	989.0	42.5	40.0	1.0	6.3	99.0	7.36	89.42	11.70	2.67
25	1030.0	44.0	41.5	1.0	6.0	99.0	7.47	89.85	11.70	2.78
26	1071.0	43.0	41.0	1.0	5.1	102.8	7.58	90.20	11.70	2.89
27	1111.0	40.0	39.5	1.0	1.3	97.8	7.68	90.47	11.90	3.00
28	1149.0	40.0	40.0	1.0	0.0	99.0	7.79	90.92	11.90	3.11
29	1186.0	40.5	40.0	1.0	—	—	7.79	91.46	11.90	3.21

TABLE B5

PRODUCTION HISTORY FOR RUN 5 - Effect of Bottom Water Thickness
[Model I, CSI, hb/hw=1.0, kaw=24μm2]

Porosity = 39.6%
Bitumen saturation = 36.8%
keff to water = 9.6μm2

Wt. sand pack = 1405.0 g
Wt. glass bead pack = 1104.0 g
Bitumen in place = 216.0 g

Rate = 300 ml/hr
BT Volume = 139.0 ml
BT pressure = 6.7kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	47.0	50.0	0.0	0.0	—	0.0	0.00	0.00	4.60	0.22
2	94.0	50.0	0.0	0.0	—	0.0	0.00	0.00	5.90	0.44
3	139.0	48.5	0.0	0.0	—	0.0	0.00	0.00	6.70	0.65
4	179.0	42.5	4.5	15.0	56.3	5.7	0.32	2.14	7.50	0.84
5	232.0	43.0	7.0	15.0	34.3	5.7	0.81	4.21	8.70	1.09
6	259.0	41.0	8.0	12.0	34.4	7.3	1.26	6.49	10.90	1.22
7	298.0	40.0	32.0	11.0	2.3	8.1	2.91	15.20	8.20	1.40
8	334.0	38.5	36.0	4.0	1.7	24.0	3.59	23.91	7.70	1.57
9	373.0	40.0	37.0	0.5	16.2	199.0	3.68	31.28	7.30	1.75
10	413.0	41.5	40.0	0.5	7.5	199.0	3.77	37.89	6.80	1.94
11	451.0	38.5	37.0	0.5	8.1	199.0	3.86	42.86	6.60	2.12
12	491.0	43.0	42.0	0.5	4.8	199.0	3.96	47.88	6.70	2.31
13	530.0	40.0	39.0	0.5	5.1	199.0	4.05	51.68	6.40	2.49
14	566.0	37.5	36.0	0.5	8.3	199.0	4.13	54.72	6.30	2.66
15	604.0	40.0	39.0	0.5	5.1	199.0	4.22	57.70	6.10	2.84
16	641.0	39.0	37.0	0.5	10.8	199.0	4.31	60.11	6.00	3.01
17	679.0	40.0	38.0	0.5	10.5	199.0	4.40	62.32	5.70	3.19
18	721.0	42.0	40.0	0.5	10.0	199.0	4.49	64.21	5.60	3.38

TABLE B6

PRODUCTION HISTORY FOR RUN 6 - Effect of Bottom Water Thickness
[CSI, hb/hw=5.2, kaw=24μm2]

Porosity = 37.6%
Bitumen saturation = 67.5%
keff to water = 2.0μm2

Wt. sand pack = 2443.0 g
Wt. glass bead pack = 373.0 g
Bitumen in place = 376.2 g

Rate = 300 ml/hr
BT Volume = 110.0 ml
BT pressure = 49.5kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	47.0	52.0	0.0	0.0	—	0.0	0.00	0.00	24.80	0.13
2	96.0	50.0	0.0	0.0	—	0.0	0.00	0.00	38.60	0.26
3	136.0	40.0	25.0	11.7	5.1	7.5	0.79	16.23	41.40	0.37
4	174.0	40.5	39.0	7.5	0.5	12.3	1.58	33.42	36.50	0.47
5	216.0	44.0	40.0	6.1	1.6	15.4	2.23	44.31	33.10	0.58
6	252.0	39.0	37.0	6.1	0.9	15.4	2.84	51.77	31.00	0.68
7	291.0	40.0	37.0	4.8	1.7	19.8	3.32	56.93	29.00	0.78
8	330.0	42.5	40.0	3.9	1.6	24.6	3.74	61.85	26.90	0.89
9	373.0	42.0	41.5	4.5	0.3	21.2	4.24	65.35	25.50	1.01
10	405.0	37.5	35.5	9.1	0.6	10.0	5.11	68.15	24.80	1.09
11	447.0	39.5	39.0	1.7	0.8	57.8	5.29	70.33	24.10	1.20
12	486.0	40.0	39.0	1.3	2.0	75.9	5.43	72.60	24.10	1.31
13	527.0	42.5	42.0	0.0	—	—	5.43	74.92	24.10	1.42
14	565.0	39.5	39.0	2.9	0.4	33.5	5.73	76.59	23.40	1.52
15	605.0	42.5	42.5	0.0	—	—	5.73	78.55	23.40	1.63
16	642.0	39.5	39.0	3.1	0.4	31.3	6.06	79.91	22.70	1.73
17	683.0	40.5	40.0	2.8	0.4	34.7	6.36	80.80	22.70	1.84
18	724.0	43.5	43.0	0.7	1.7	141.9	6.44	82.13	22.70	1.95
19	763.0	42.0	41.5	0.0	—	—	6.44	83.37	22.70	2.06

TABLE B6 (CONTINUED)

PRODUCTION HISTORY FOR RUN 6 - Effect of Bottom Water Thickness
[Model I, CSI, hb/hw=5.2, kaw=24μm2]

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
20	802.0	42.0	42.0	0.7	0.0	141.9	6.52	84.51	22.70	2.16
21	842.0	42.0	41.5	2.4	0.5	40.7	6.79	85.31	22.10	2.27
22	882.0	44.5	44.5	8.4	0.0	10.9	7.80	86.06	22.10	2.38
23	922.0	39.0	38.0	16.3	0.2	5.1	9.47	85.78	22.10	2.49
24	958.0	39.0	39.0	0.8	0.0	124.0	9.55	86.59	22.10	2.58
25	995.0	38.0	38.0	0.5	0.0	199.0	9.60	87.17	22.10	2.68
26	1033.0	40.0	40.0	0.0	—	—	9.60	87.84	22.10	2.78
27	1072.0	40.0	40.0	0.0	—	—	9.60	88.37	21.40	2.89
28	1112.0	44.0	44.0	2.8	0.0	—	9.90	89.05	21.40	3.00
29	1150.0	39.5	39.5	3.0	—	38.8	9.90	89.54	21.40	3.10

TABLE B7

PRODUCTION HISTORY FOR RUN 7
[Model I, CSI, hb/hw=5.2, kaw=24μm2]

Porosity = 34.5%
Bitumen saturation = 77.9%
keff to water = 3.7μm2

Wt. sand pack = 2585.0 g
Wt. glass bead pack = 364.0 g
Bitumen in place = 398.2 g

Rate = 300 ml/hr
BT Volume = 105.0 ml
BT pressure = 40.9kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	47.0	50.0	0.0	0.0	—	0.0	0.00	0.00	21.44	0.12
2	98.0	49.0	0.0	0.0	—	0.0	0.00	0.00	32.30	0.25
3	134.0	39.0	12.5	11.6	18.3	7.6	0.37	8.25	34.11	0.34
4	172.0	40.0	38.0	5.6	0.9	16.9	0.91	27.28	31.19	0.44
5	209.0	39.5	38.0	4.4	0.9	21.7	1.34	39.83	29.10	0.53
6	250.0	40.0	38.0	2.0	2.6	49.0	1.53	48.20	28.13	0.64
7	288.0	41.0	40.0	3.3	0.8	29.3	1.87	55.27	27.57	0.73
8	329.0	43.0	41.0	9.2	0.5	9.9	2.83	59.70	27.01	0.84
9	369.0	42.5	40.5	4.4	1.1	21.7	3.28	63.72	26.18	0.94
10	408.0	41.0	40.5	3.8	0.3	25.2	3.68	67.17	26.04	1.04
11	447.0	40.0	38.5	2.0	1.9	49.0	3.87	69.75	26.04	1.14
12	485.0	40.2	40.0	0.0	—	—	3.87	72.54	25.62	1.24
13	522.0	41.5	41.0	0.8	1.5	124.0	3.96	75.19	25.48	1.33
14	561.0	42.0	41.5	0.0	—	—	3.96	77.36	25.06	1.43
15	602.0	42.0	42.0	4.4	0.0	21.7	4.43	78.76	25.06	1.53
16	642.0	41.7	41.0	0.0	—	—	4.43	80.24	24.92	1.64
17	683.0	42.3	42.0	0.0	—	—	4.43	81.57	24.65	1.74
18	722.0	40.5	39.0	0.0	—	—	4.43	82.57	24.51	1.84
19	762.0	43.5	43.5	0.0	—	—	4.43	83.94	24.78	1.94

TABLE B7 (CONTINUED)

PRODUCTION HISTORY FOR RUN 7
[Model I, CSI, hb/hw=5.2, kaw=24μm2]

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
20	793.0	47.0	46.0	0.0	—	—	4.43	86.46	24.37	2.02
21	843.0	38.5	38.5	0.0	—	—	4.43	85.90	24.51	2.15
22	882.0	38.5	38.5	0.0	—	—	4.43	86.47	24.37	2.25
23	917.0	38.5	37.0	0.0	—	—	4.43	87.20	24.37	2.34
24	954.0	37.5	36.5	0.0	—	—	4.43	87.64	24.37	2.43
25	991.0	40.0	39.0	0.0	—	—	4.43	88.31	24.23	2.52
26	1037.0	46.0	45.0	0.0	—	—	4.43	88.73	24.23	2.64
27	1072.0	40.0	38.5	0.0	—	—	4.43	89.42	24.23	2.73
28	1117.0	46.5	45.0	0.0	—	—	4.43	89.85	24.23	2.85
29	1154.0	36.5	35.0	0.0	—	—	4.43	90.00	24.09	2.94
30	1190.0	39.0	35.0	0.0	—	—	4.43	90.22	24.09	3.03

TABLE B8

PRODUCTION HISTORY FOR RUN 8 - Effect of Injection Rate
[CSI, hb/hw=5.2, kaw=24μm2]

Porosity = 38.2%
Bitumen saturation = 66.5%
keff to water = 2.7μm2

Wt. sand pack = 2429.0 g
Wt. glass bead pack = 357.7 g
Bitumen in place = 374.0 g

Rate = 15 ml/hr
BT Volume = 103.0 ml
BT pressure = 6.3kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	44.0	46.0	0.0	0.0	—	0.0	0	0.00	4.05	0.12
2	61.0	17.5	0.0	0.0	—	0.0	0.00	0.00	4.47	0.17
3	103.0	43.5	0.0	0.0	—	0.0	0.00	0.00	6.28	0.28
4	117.0	15.0	13.0	14.4	3.9	5.9	0.51	9.51	5.44	0.32
5	132.0	15.0	15.0	12.0	1.8	7.3	1.00	18.43	5.17	0.36
6	152.0	21.0	21.0	12.6	2.6	6.9	1.71	28.08	4.75	0.41
7	181.0	30.5	30.5	15.9	4.8	5.3	3.03	37.75	4.47	0.49
8	207.0	28.5	28.5	6.6	1.9	14.2	3.54	45.87	4.33	0.56
9	348.0	142.0	142.0	6.3	8.9	14.9	5.96	65.52	4.05	0.94
10	368.0	19.5	19.5	1.0	0.2	99.0	6.01	67.20	4.19	1.00
11	383.0	16.5	16.5	2.2	0.4	44.5	6.11	68.79	4.05	1.04
12	398.0	17.0	17.0	3.3	0.6	29.3	6.26	70.32	4.19	1.08
13	422.0	24.0	24.0	3.3	0.8	29.3	6.48	71.82	4.19	1.14
14	437.0	14.0	14.0	3.3	0.5	29.3	6.60	72.46	4.19	1.18
15	453.0	14.5	14.5	2.9	0.4	33.5	6.72	73.00	4.19	1.23
16	466.0	10.2	10.5	3.3	0.0	29.3	6.81	73.15	4.19	1.26
17	481.0	14.0	13.5	8.7	1.7	10.5	7.13	73.43	5.58	1.30
18	499.0	18.5	18.5	14.8	2.7	5.8	7.87	73.94	5.44	1.35

TABLE B8 (CONTINUED)

PRODUCTION HISTORY FOR RUN 8 - Effect of Injection Rate
[Model I, CSI, hb/hw=5.2, kaw=24μm2]

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
19	513.0	13.5	13.5	15.3	2.1	5.5	8.43	74.15	5.44	1.39
20	529.0	17.5	17.5	12.8	2.2	6.8	9.04	74.79	4.61	1.43
21	559.0	30.0	30.0	11.1	3.3	8.0	9.94	75.55	4.19	1.51

TABLE B9

PRODUCTION HISTORY FOR RUN 9 - Effect of Bottom Water Permeability & Well Interval
[CSI, hb/hw=5.2, kaw=2μm2]

Porosity = 40.2%
Bitumen saturation = 56.5%
keff to water = 1.9μm2

Wt. sand pack = 2325.50 g
Wt. glass bead pack = 377.1 g
Bitumen in place = 341.8 g

Rate = 300 ml/hr
BT Volume = 89.0 ml
BT pressure = 46.1kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	44.0	44.0	0.0	0.0	—	0.0	0.00	0.00	34.24	0.13
2	89.0	47.5	0.0	0.0	—	0.0	0.00	0.00	46.07	0.27
3	123.0	35.0	17.0	31.0	3.4	2.2	1.59	9.54	68.20	0.37
4	160.0	40.0	30.0	17.8	1.9	4.6	3.20	22.74	71.13	0.48
5	197.0	40.0	36.0	17.8	0.6	4.6	5.13	33.49	68.48	0.59
6	236.0	40.0	38.0	17.8	0.3	4.6	7.17	41.19	64.03	0.71
7	275.0	43.0	43.0	13.5	0.0	6.4	8.91	48.88	62.60	0.83
8	312.0	39.0	38.0	11.7	0.2	7.5	10.25	53.84	57.90	0.94
9	349.0	39.0	38.0	12.8	0.2	6.8	11.72	57.62	54.14	1.05
10	394.0	49.0	48.0	10.8	0.2	8.3	13.28	61.91	50.67	1.19
11	429.0	38.0	37.0	13.2	0.2	6.6	14.75	64.34	48.58	1.29
12	462.0	37.0	36.0	9.0	0.3	10.1	15.73	66.84	46.91	1.39
13	497.0	38.0	37.0	7.9	0.3	11.7	16.61	68.99	45.15	1.50
14	533.0	38.0	37.0	8.0	0.3	11.5	17.50	70.72	43.98	1.61
15	571.0	38.0	38.0	7.0	0.0	13.3	18.30	72.20	42.59	1.72
16	607.0	37.5	37.0	6.4	0.2	14.6	19.02	73.62	41.76	1.83
17	647.0	45.5	45.0	4.5	0.2	21.2	19.63	75.71	40.78	1.95
18	687.0	42.5	42.0	6.0	0.2	15.7	20.39	77.05	39.67	2.07
19	733.0	48.0	47.0	8.0	0.3	11.5	21.52	78.11	38.42	2.21
20	769.0	39.0	38.0	9.0	0.3	10.1	22.55	78.95	37.58	2.32
21	807.0	39.0	38.0	7.7	0.3	12.0	23.43	79.58	36.61	2.43

TABLE B9 (CONTINUED)

PRODUCTION HISTORY FOR RUN 9 - Effect of Bottom Water Permeability & Well Interval

[CSI, hb/hw=5.2, kaw=2μm2]

22	847.0	42.5	42.0	5.1	0.2	18.6	24.08	80.53	35.77	2.55
23	882.0	37.5	37.0	6.1	0.2	15.4	24.76	81.27	35.08	2.66
24	915.0	36.5	36.5	4.6	0.0	20.7	25.26	82.15	34.38	2.76
25	945.0	33.5	33.0	5.8	0.3	16.2	25.84	82.83	34.10	2.85
26	987.0	42.5	42.0	5.5	0.2	17.2	26.54	83.33	33.55	2.97
27	1035.0	49.5	49.0	5.1	0.2	18.6	27.29	83.95	32.71	3.12
28	1073.0	40.5	40.5	4.1	0.0	23.4	27.79	84.60	32.43	3.23
29	1114.0	45.0	45.0	10.8	0.0	8.3	29.25	85.09	31.87	3.36
30	1158.0	45.0	45.0	5.3	0.0	17.9	29.97	85.54	31.46	3.49
31	1172.0	14.0	14.0	5.1	0.0	18.6	30.19	85.65	31.46	3.53
32	1214.0	46.0	45.0	5.2	0.4	18.2	30.89	86.20	30.34	3.66
33	1258.0	44.0	43.0	5.0	0.5	19.0	31.54	86.43	29.65	3.79
34	1313.0	49.0	48.0	2.8	0.7	34.7	31.94	86.37	28.53	3.96
35	1353.0	45.0	45.0	4.0	0.0	24.0	32.49	87.01	27.98	4.08
36	1410.0	65.0	65.0	4.6	0.0	20.7	33.39	87.89	26.86	4.25
37	1444.0	37.5	36.0	4.9	0.9	19.4	33.92	88.19	26.59	4.35
38	1480.0	39.0	38.0	5.4	0.5	17.5	34.54	88.47	26.31	4.46
39	1512.0	40.0	39.0	4.0	0.6	24.0	35.01	89.07	26.03	4.56
40	1556.0	38.0	37.0	3.4	0.8	28.4	35.39	88.85	25.75	4.69
41	1598.0	41.5	41.0	3.5	0.3	27.6	35.82	88.99	25.47	4.81
42	1641.0	45.0	43.0	3.1	1.5	31.3	36.22	89.20	24.92	4.94
43	1686.0	47.0	46.0	6.5	0.3	14.4	37.12	89.37	24.64	5.08
44	1726.0	42.0	42.0	10.3	0.0	8.7	38.43	89.48	24.22	5.20
45	1766.0	40.0	40.0	3.7	0.0	26.0	38.87	89.64	24.08	5.32
46	1806.0	42.0	42.0	2.5	0.0	39.0	39.19	89.92	23.66	5.44
47	1844.0	41.0	41.0	2.1	0.0	46.6	39.45	90.24	23.66	5.56
48	1881.0	40.0	40.0	5.1	0.0	18.6	40.06	90.49	23.38	5.67
49	1926.0	46.0	46.0	2.5	0.0	39.0	40.41	90.70	23.25	5.80
50	1963.0	39.0	39.0	2.1	0.0	46.6	40.65	90.94	23.23	5.91
51	2003.0	44.0	44.0	4.0	0.0	24.0	41.19	91.23	22.97	6.04

TABLE B10

PRODUCTION HISTORY FOR RUN 10 - Effect of Bottom Water Permeability & Well Interval
[CSI, hb/hw=5.2, kaw=24μm2]

Porosity = 40.8%
Bitumen saturation = 55.9%
keff to water = 4.7μm2

Wt. sand pack = 2341.2 g
Wt. glass bead pack = 340.3 g
Bitumen in place = 344.2 g

Rate = 300 ml/hr
BT Volume = 153.0 ml
BT pressure = 47.6kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	53.0	51.0	0.0	0.0	—	0.0	0.00	0.00	9.19	0.16
2	100.0	48.0	0.0	0.0	—	0.0	0.00	0.00	14.75	0.30
3	153.0	50.0	0.0	0.0	—	0.0	0.00	0.00	47.60	0.46
4	185.0	40.0	28.0	30.0	1.4	2.3	2.51	10.59	35.35	0.55
5	220.0	41.0	39.0	13.1	0.4	6.6	4.04	24.31	31.04	0.66
6	258.0	40.0	38.0	14.1	0.4	6.1	5.65	33.38	27.84	0.77
7	298.0	41.5	40.0	14.6	0.3	5.8	7.39	40.37	25.75	0.89
8	336.0	42.5	41.5	15.3	0.2	5.5	9.29	46.26	23.94	1.01
9	373.0	38.5	38.0	11.4	0.1	7.8	10.59	50.70	22.41	1.12
10	413.0	42.0	41.0	15.3	0.2	5.5	12.47	54.20	21.30	1.24
11	452.0	40.0	39.0	15.6	0.2	5.4	14.29	56.80	20.60	1.35
12	492.0	42.0	41.0	11.4	0.2	7.8	15.69	59.57	20.60	1.47
13	530.0	40.0	40.0	11.3	0.0	7.8	17.04	61.99	19.63	1.59
14	566.0	37.5	37.0	7.2	0.2	12.9	17.84	64.12	19.07	1.69
15	602.0	39.0	39.0	6.7	0.0	13.9	18.62	66.33	18.51	1.80
16	645.0	46.0	46.0	6.1	0.0	15.4	19.46	68.60	17.96	1.93
17	684.0	42.0	42.0	5.8	0.0	16.2	20.19	70.47	17.54	2.05
18	725.0	43.0	43.0	4.9	0.0	19.4	20.82	72.13	17.26	2.17
19	762.0	40.0	40.0	4.5	0.0	21.2	21.36	73.64	16.98	2.28
20	804.0	44.0	44.0	4.5	0.0	21.2	21.95	75.02	16.56	2.41
21	845.0	44.0	44.0	3.5	0.0	27.6	22.41	76.40	16.42	2.53

TABLE B10 (CONTINUED)

PRODUCTION HISTORY FOR RUN 10 - Effect of Bottom Water Permeability & Well Interval
[CSI, hb/hw=5.2, kaw=24μm2]

22	885.0	41.0	41.0	4.8	0.0	19.8	23.00	77.36	16.15	2.65
23	924.0	40.0	40.0	5.3	0.0	17.9	23.63	78.20	16.01	2.77
24	957.0	38.0	37.5	4.7	0.3	20.3	24.16	79.23	15.87	2.86
25	998.0	44.5	44.0	4.3	0.3	22.3	24.73	80.20	15.45	2.99
26	1039.0	42.5	41.5	5.1	0.5	18.6	25.36	80.82	15.31	3.11
27	1080.0	42.0	41.0	5.1	0.5	18.6	25.99	81.36	15.03	3.23
28	1116.0	40.0	39.0	4.6	0.6	20.7	26.52	82.07	14.75	3.34
29	1154.0	39.0	38.5	4.3	0.3	22.3	27.02	82.56	14.62	3.45
30	1190.0	37.0	36.0	5.7	0.5	16.5	27.63	82.91	14.34	3.56
31	1221.0	32.0	32.0	3.5	0.0	27.6	27.97	83.34	15.03	3.65
32	1258.0	38.0	37.0	8.5	0.3	10.8	28.91	83.58	16.01	3.76
33	1299.0	44.0	43.0	3.5	0.7	27.6	29.36	84.13	15.73	3.89
34	1341.0	45.0	43.0	3.5	1.3	27.6	29.81	84.59	15.45	4.01
35	1384.0	45.0	43.0	3.1	1.5	31.3	30.21	84.98	15.31	4.14
36	1429.0	47.0	45.0	2.7	1.6	36.0	30.57	85.36	15.17	4.28
37	1467.0	40.0	38.0	2.6	2.0	37.5	30.87	85.67	14.89	4.39
38	1509.0	45.0	42.0	2.7	2.6	36.0	31.21	86.00	14.89	4.52
39	1551.0	44.0	42.0	2.6	1.8	37.5	31.54	86.31	14.89	4.64
40	1589.0	41.0	39.0	3.5	1.5	27.6	31.94	86.61	14.75	4.76
41	1624.0	38.5	36.5	3.6	1.5	26.8	32.34	86.91	14.62	4.86
42	1660.0	39.0	37.0	2.3	1.2	42.5	32.59	87.20	14.47	4.97
43	1700.0	43.0	43.0	1.9	0.0	51.6	32.84	87.63	14.47	5.09
44	1736.0	38.0	37.0	3.4	0.8	28.4	33.21	87.88	14.47	5.20
45	1787.0	52.0	51.0	4.8	0.4	19.8	33.95	88.08	14.34	5.35
46	1827.0	42.5	41.5	5.8	0.4	16.2	34.67	88.30	14.34	5.47
47	1880.0	50.0	49.0	1.3	1.6	75.9	34.86	88.38	14.34	5.63
48	1923.0	46.0	45.0	2.3	1.0	42.5	35.17	88.69	14.20	5.76
49	1958.0	37.0	37.0	2.3	0.0	42.5	35.42	88.95	14.20	5.86
50	1993.0	38.0	38.0	2.3	0.0	42.5	35.68	89.25	14.20	5.96

TABLE B11

PRODUCTION HISTORY FOR RUN 11 - Effect of Bottom Water Permeability & Well Interval Distance
[Model I, CSI, hb/hw=5.2, kaw=200µm2]

Porosity = 40.3%
Bitumen saturation = 54.2%
keff to water = 5.5µm2

Wt. sand pack = 2278.0 g
Wt. glass bead pack = 390.3 g
Bitumen in place = 332.6 g

Rate = 300 ml/hr
BT Volume = 101.0 ml
BT pressure = 12.8 kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	44.0	47.5	0.0	0.0	—	0.0	0.00	0.00	8.66	0.14
2	88.0	47.5	0.0	0.0	—	0.0	0.00	0.00	9.91	0.27
3	101.0	17.5	0.0	0.0	—	0.0	0.00	0.00	12.83	0.31
4	140.0	37.5	34.5	1.0	8.7	99.0	0.10	24.40	10.60	0.43
5	176.0	39.5	37.5	1.0	5.3	99.0	0.22	40.50	10.19	0.54
6	219.0	42.0	39.5	1.0	6.3	99.0	0.34	50.40	9.91	0.68
7	256.0	40.0	38.0	1.0	5.3	99.0	0.45	57.81	9.91	0.79
8	294.0	41.5	39.5	1.0	5.1	99.0	0.57	63.64	9.77	0.91
9	334.0	40.0	38.0	1.0	5.3	99.0	0.68	67.28	9.63	1.03
10	371.0	42.0	40.0	1.0	5.0	99.0	0.80	71.25	9.63	1.15
11	412.0	42.0	40.0	1.0	5.0	99.0	0.92	73.77	9.49	1.28
12	456.0	45.0	43.0	1.0	4.7	99.0	1.05	75.99	9.35	1.41
13	502.0	48.0	46.0	1.0	4.3	99.0	1.19	78.10	9.49	1.55
14	547.0	48.0	47.0	1.0	2.1	99.0	1.33	80.18	9.49	1.69
15	587.0	41.5	39.5	1.0	5.1	99.0	1.45	81.38	9.49	1.82
16	627.0	42.5	41.5	2.0	1.2	49.0	1.70	82.67	9.35	1.94
17	666.0	42.5	41.5	2.0	1.2	49.0	1.95	83.94	9.22	2.06
18	721.0	55.0	51.0	2.0	3.9	49.0	2.26	84.47	9.22	2.23
19	760.0	42.5	42.0	2.0	0.6	49.0	2.51	85.55	9.08	2.35
20	804.0	45.0	42.0	2.0	3.6	49.0	2.76	85.98	8.93	2.49

TABLE B11 CONTINUED

PRODUCTION HISTORY FOR RUN 11 - Effect of Bottom Water Permeability & Interwell Distance
[Model I, CSI, hb/hw=5.2, kaw=200μm2]

21	844.0	42.0	40.0	2.0	2.5	49.0	3.00	86.55	8.80	2.61
22	888.0	44.0	42.0	2.0	2.4	49.0	3.25	86.90	8.94	2.75
23	936.0	49.0	48.5	2.0	0.5	49.0	3.55	87.52	8.94	2.90
24	984.0	47.0	47.0	2.0	0.0	49.0	3.83	87.93	8.94	3.05
25	1023.0	42.0	41.5	2.0	0.6	49.0	4.08	88.56	8.94	3.17
26	1062.0	42.5	42.0	2.0	0.6	49.0	4.33	89.18	8.94	3.29
27	1104.0	42.0	41.0	2.0	1.2	49.0	4.58	89.43	8.94	3.42
28	1145.0	44.5	43.5	2.0	1.1	49.0	4.84	89.95	8.94	3.55
29	1191.0	47.5	47.0	2.0	0.5	49.0	5.12	90.34	8.94	3.69
30	1239.0	53.0	50.0	2.0	3.0	49.0	5.42	90.80	12.83	3.84
31	1283.0	40.0	40.0	3.0	0.0	32.3	5.78	90.71	12.27	3.97
32	1323.0	40.0	36.0	3.0	3.7	32.3	6.11	90.60	14.64	4.10
33	1366.0	43.5	43.0	3.0	0.4	32.3	6.50	90.80	13.94	4.23
34	1407.0	42.5	42.0	3.0	0.4	32.3	6.88	91.05	13.94	4.36
35	1448.0	43.0	40.0	5.0	1.5	19.0	7.48	91.10	13.94	4.48
36	1494.0	48.0	45.0	3.0	2.2	32.3	7.88	91.22	14.50	4.63
37	1532.0	39.5	38.5	3.0	0.9	32.3	8.23	91.39	15.19	4.74
38	1573.0	44.5	44.0	3.0	0.4	32.3	8.63	91.72	15.75	4.87
39	1615.0	42.0	40.0	3.0	1.7	32.3	8.99	91.74	16.03	5.00
40	1658.0	46.0	44.0	3.0	1.5	32.3	9.38	91.94	16.58	5.13
41	1697.0	40.0	38.5	3.0	1.3	32.3	9.73	92.02	16.72	5.25
42	1736.0	42.0	40.0	3.0	1.7	32.3	10.09	92.19	16.86	5.38
43	1772.0	42.5	39.5	3.0	2.5	32.3	10.45	92.48	17.00	5.49
44	1813.0	43.5	42.5	3.0	0.8	32.3	10.83	92.66	17.28	5.61
45	1860.0	48.5	47.5	3.0	0.7	32.3	11.26	92.80	17.28	5.76
46	1900.0	43.0	41.5	3.0	1.2	32.3	11.63	92.96	17.42	5.88
47	1938.0	40.0	39.0	3.0	0.9	32.3	11.99	93.09	17.84	6.00

TABLE B12

PRODUCTION HISTORY FOR RUN 12 - Effect of Well Interval
[Model I, CSI, hb/hw=5.2, kaw=24μm2]

Porosity = 41.4%
Bitumen saturation = 51.2%
keff to water = 3.6μm2

Wt. sand pack = 2309.0 g
Wt. glass bead pack = 351.7 g
Bitumen in place = 323.3 g

Rate = 300 ml/hr
BT Volume = 119.0 ml
BT pressure = 45.0kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	44.0	47.0	0.0	0.0	—	0	0.00	0.00	22.70	0.14
2	94.0	50.0	0.0	0.0	—	0	0.00	0.00	38.97	0.30
3	119.0	25.5	0.0	0.0	—	0	0.00	0.00	44.66	0.38
4	158.0	40.0	33.0	11.0	1.9	8.1	1.16	18.59	40.22	0.50
5	202.0	45.0	41.0	7.2	1.4	12.9	2.10	33.38	37.85	0.64
6	240.0	42.5	39.0	6.1	1.5	15.4	2.85	43.35	36.19	0.76
7	284.0	45.0	41.0	4.5	2.2	21.2	3.44	50.42	35.07	0.90
8	326.0	47.0	44.5	4.5	1.2	21.2	4.08	56.96	34.38	1.04
9	368.0	42.0	38.0	4.5	2.3	21.2	4.63	60.32	33.55	1.17
10	416.0	52.5	50.0	3.9	1.3	24.6	5.25	64.91	32.85	1.33
11	459.0	42.5	39.5	3.9	1.9	24.6	5.74	67.10	32.16	1.46
12	503.0	46.0	43.5	3.9	1.5	24.6	6.28	69.54	31.32	1.60
13	543.0	44.5	42.5	2.0	2.4	49.0	6.55	72.09	31.18	1.73
14	589.0	47.0	46.0	2.0	1.1	49.0	6.84	74.11	30.76	1.88
15	631.0	45.0	44.0	2.0	1.1	49.0	7.12	76.01	30.63	2.01
16	674.0	45.0	41.0	1.9	5.1	51.6	7.37	77.13	30.21	2.15
17	713.0	40.0	39.5	1.9	0.7	51.6	7.61	78.35	29.93	2.27
18	757.0	47.5	46.5	1.9	1.1	51.6	7.89	79.82	29.93	2.41
19	802.0	47.5	46.5	1.9	1.1	51.6	8.17	81.03	29.65	2.55
20	847.0	47.5	45.5	1.9	2.3	51.6	8.45	81.99	29.51	2.70

TABLE B12 CONTINUED

PRODUCTION HISTORY FOR RUN 12 - Effect of Well Interval
[Model I, CSI, hb/hw=5.2, kaw=24μm2]

21	888.0	42.5	41.5	2.0	1.2	49.0	8.71	82.79	29.51	2.83
22	925.0	41.5	39.5	2.0	2.5	49.0	8.96	83.66	29.24	2.95
23	966.0	43.5	43.5	2.0	0.0	49.0	9.24	84.52	29.51	3.08
24	1011.0	49.5	49.0	2.0	0.5	49.0	9.55	85.51	29.51	3.22
25	1050.0	40.0	39.5	1.4	0.9	70.4	9.73	86.04	29.65	3.35
26	1091.0	45.0	43.0	1.4	3.3	70.4	9.92	86.70	29.65	3.48
27	1134.0	45.0	44.0	1.9	1.2	51.6	10.19	87.22	29.65	3.61
28	1182.0	48.5	47.5	2.0	1.1	49.0	10.49	87.61	29.65	3.77
29	1219.0	42.0	41.5	2.0	0.6	49.0	10.75	88.29	29.37	3.88
30	1264.0	47.5	47.5	2.3	0.0	42.5	11.10	88.82	29.10	4.03
31	1306.0	46.0	44.5	4.1	0.8	23.2	11.69	89.23	28.82	4.16
32	1350.0	45.0	45.0	4.1	0.0	23.2	12.28	89.51	28.68	4.30
33	1388.0	40.0	40.0	4.1	0.0	23.2	12.81	89.83	28.82	4.42
34	1428.0	43.5	43.5	4.1	0.0	23.2	13.38	90.23	28.40	4.55
35	1468.0	40.0	40.0	4.1	0.0	23.2	13.91	90.38	28.26	4.68
36	1509.0	43.5	43.5	4.1	0.0	23.2	14.49	90.69	28.12	4.81
37	1559.0	50.0	50.0	4.1	0.0	23.2	15.14	90.86	28.12	4.97
38	1598.0	42.0	42.0	2.4	0.0	40.5	15.47	91.20	27.85	5.09
39	1640.0	44.5	44.5	2.4	0.0	40.5	15.81	91.52	27.71	5.22
40	1680.0	43.0	43.0	2.4	0.0	40.5	16.14	91.84	27.71	5.35
41	1721.0	44.5	44.5	2.4	0.0	40.5	16.48	92.17	27.71	5.48
42	1762.0	45.0	44.0	2.4	0.9	40.5	16.82	92.46	27.29	5.61
43	1804.0	46.0	46.0	2.4	0.0	40.5	17.17	92.80	27.29	5.75
44	1852.0	48.0	48.0	2.4	0.0	40.5	17.54	92.92	27.29	5.90
45	1896.0	41.0	41.0	2.4	0.0	40.5	17.85	92.88	27.15	6.04

TABLE B13

PRODUCTION HISTORY FOR RUN 13 - Effect of Well Interval Repeat Base Run
[Model I, CSI, hb/hw=5.2, kaw=24µm2]

Porosity = 40.6%
Bitumen saturation = 56.5%
keff to water = 12.2µm2

Wt. sand pack = 2304.0 g
Wt. glass bead pack = 360.0 g
Bitumen in place = 326.6 g

Rate = 300 ml/hr
BT Volume = 69.0 ml
BT pressure = 15.7kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
1	57.0	52.0	0.0	0.0	—	0.0	0.00	0.00	15.70	0.17
2	69.0	12.0	0.0	0.0	—	0.0	0.00	0.00	17.50	0.21
3	103.0	59.0	20.0	10.2	19.1	8.8	0.62	17.44	15.90	0.32
4	153.0	48.5	43.0	9.3	1.4	9.8	1.85	37.23	13.40	0.47
5	199.0	50.0	45.0	5.0	2.2	19.0	2.54	50.11	12.20	0.61
6	246.0	50.0	45.0	4.0	2.8	24.0	3.09	58.09	11.60	0.75
7	295.0	50.0	46.5	6.0	1.3	15.7	3.94	63.26	11.20	0.90
8	342.0	50.0	47.0	2.8	2.3	34.7	4.35	67.93	10.70	1.05
9	389.0	50.0	45.5	2.8	3.5	34.7	4.74	71.09	10.30	1.19
10	443.0	52.5	48.0	2.8	3.3	34.7	5.15	72.95	9.80	1.36
11	487.0	50.0	46.5	2.8	2.7	34.7	5.55	75.64	8.70	1.49
12	534.0	50.0	47.0	2.8	2.3	34.7	5.95	77.54	9.50	1.64
13	586.0	53.0	48.5	1.8	5.2	54.6	6.22	78.79	9.50	1.79
14	632.0	51.5	48.5	1.8	3.4	54.6	6.48	80.59	9.20	1.94
15	683.0	52.0	48.5	1.8	4.0	54.6	6.75	81.54	9.20	2.09
16	735.0	50.0	47.0	1.8	3.5	54.6	7.01	82.05	9.10	2.25
17	791.0	52.0	48.0	1.8	4.6	54.6	7.27	82.20	9.00	2.42
18	827.0	52.0	48.0	1.8	4.6	54.6	7.54	84.33	9.00	2.53
19	877.0	52.0	50.0	1.8	2.2	54.6	7.82	85.12	8.90	2.69

TABLE B13 (CONTINUED)

PRODUCTION HISTORY FOR RUN 13 - Effect of Well Interval Repeat Base Run
[Model I, CSI, hb/hw=5.2, kaw=24μm2]

20	921.0	50.0	46.0	1.8	4.8	54.6	8.07	85.96	8.70	2.82
21	969.0	50.0	47.5	1.0	5.3	99.0	8.21	86.55	8.70	2.97
22	1019.0	50.0	47.0	1.0	6.4	99.0	8.36	86.87	8.70	3.12
23	1070.0	52.5	50.0	1.0	5.0	99.0	8.51	87.36	8.70	3.28
24	1117.0	49.0	46.0	1.0	6.5	99.0	8.65	87.76	8.60	3.42
25	1166.0	53.0	50.0	1.0	6.0	99.0	8.80	88.31	8.60	3.57
26	1211.0	50.0	46.0	1.0	8.7	99.0	8.95	88.79	8.60	3.71
27	1258.0	49.5	47.5	1.0	4.2	99.0	9.09	89.21	8.60	3.85
28	1308.0	50.0	47.0	1.0	6.4	99.0	9.24	89.36	8.60	4.00
29	1358.0	50.0	47.0	1.0	6.4	99.0	9.38	89.50	9.80	4.16
30	1407.0	52.0	49.0	1.0	6.1	99.0	9.53	89.83	9.90	4.31
31	1456.0	50.0	48.0	1.0	4.2	99.0	9.68	90.07	9.70	4.46
32	1502.0	50.0	48.0	1.0	4.2	99.0	9.82	90.47	9.70	4.60
33	1552.0	50.0	47.5	1.0	5.3	99.0	9.97	90.59	9.70	4.75
34	1600.0	52.5	50.0	1.0	5.0	99.0	10.12	90.97	9.70	4.90
35	1650.0	53.0	50.0	1.0	6.0	99.0	10.27	91.21	9.70	5.05
36	1702.0	53.0	51.0	1.0	3.9	99.0	10.43	91.39	9.70	5.21
37	1752.0	53.0	50.0	1.0	6.0	99.0	10.58	91.61	9.70	5.36
38	1801.0	48.0	45.0	1.0	6.7	99.0	10.72	91.59	9.70	5.51
39	1847.0	50.0	47.0	1.0	6.4	99.0	10.87	91.83	9.50	5.66
40	1895.0	50.0	48.0	1.0	4.2	99.0	11.01	92.01	9.30	5.80
41	1942.0	50.0	48.0	1.0	4.2	99.0	11.16	92.23	9.20	5.95
42	1992.0	50.0	47.0	1.0	6.4	99.0	11.30	92.25	9.20	6.10

TABLE B14

PRODUCTION HISTORY FOR RUN 14 - Homogeneous Pack Run

[Model II, Continuous Solvent Injection;CSI, OB Press=1000 kPag, Ip=28%, Pp=71% OS depth]

Porosity = 39.0%
Bitumen saturation = 68.0% PV
keff to water = 0.6μm2

Wt. sand pack = 5235.0 g
Wt. glass bead pack = N/A
Bitumen in place = 743.0 g

Rate = 300 ml/hr
BT Volume = 284.0ml
BT pressure = 510.0kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV /recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
0	0.0	0.0	0.0	0.0	—	0.0	0.00	0.00	0.00	0.00
1	94.0	50.0	0.0	0.0	—	0.0	0.00	0.00	140.00	0.13
2	154.0	50.0	0.0	0.0	—	0.0	0.00	0.00	262.00	0.21
3	206.0	45.5	0.0	0.0	—	0.0	0.00	0.00	365.00	0.29
4	264.0	48.0	0.0	0.0	—	0.0	0.00	0.00	476.00	0.37
5	284.0	10.0	0.0	0.0	—	0.0	0.00	0.00	510.00	0.39
6	331.0	52.0	52.0	39.6	0.0	1.5	2.85	9.49	414.00	0.46
7	371.0	45.0	45.0	36.4	0.0	1.7	5.12	16.18	358.00	0.51
8	417.0	50.0	50.0	30.0	0.0	2.3	7.20	22.79	296.00	0.58
9	466.0	52.0	52.0	25.6	0.0	2.9	9.04	28.69	255.00	0.65
10	513.0	50.0	50.0	21.4	0.0	3.7	10.52	33.73	234.00	0.71
11	569.0	50.0	50.0	13.0	0.0	6.7	11.43	38.05	200.00	0.79
12	603.0	47.0	47.0	17.0	0.0	4.9	12.53	42.37	193.00	0.84
13	643.0	43.0	43.0	15.0	0.0	5.7	13.43	45.42	186.00	0.89
14	688.0	47.5	47.5	17.0	0.0	4.9	14.54	48.18	179.00	0.95
15	761.0	47.0	47.0	10.9	0.0	8.2	15.25	49.06	169.00	1.05
16	777.0	47.0	47.0	17.2	0.0	4.8	16.37	53.06	160.00	1.08
17	823.0	50.0	50.0	13.0	0.0	6.7	17.27	55.38	159.00	1.14
18	868.0	47.0	47.0	14.0	0.0	6.1	18.18	57.17	152.00	1.20

TABLE B14 (CONTINUED)

PRODUCTION HISTORY FOR RUN 14 - Homogeneous Pack Run
[Model II, Continuous Solvent Injection;CSI, OB Press=1000 kPag, Ip=28%, Pp=71% OS depth]

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
19	912.0	43.0	43.0	8.8	0.0	10.4	18.71	58.71	131.00	1.26
20	956.0	45.5	45.5	13.0	0.0	6.7	19.53	60.15	138.00	1.32
21	1010.0	54.0	54.0	9.8	0.0	9.2	20.26	61.76	138.00	1.40
22	1055.0	50.0	50.0	10.9	0.0	8.2	21.01	63.34	138.00	1.46
23	1101.0	48.0	48.0	9.8	0.0	9.2	21.67	64.63	131.00	1.52
24	1146.0	48.5	48.5	9.8	0.0	9.2	22.32	65.91	124.00	1.59
25	1192.0	50.0	50.0	9.8	0.0	9.2	23.00	67.15	124.00	1.65
26	1236.0	45.0	45.0	8.8	0.0	10.4	23.55	68.08	124.00	1.71
27	1326.0	93.0	93.0	7.7	0.0	12.0	24.54	69.93	121.00	1.84
28	1374.0	50.0	50.0	7.7	0.0	12.0	25.08	70.85	114.00	1.90
29	1757.0	391.0	391.0	9.8	0.0	9.2	30.38	75.48	110.00	2.43
30	1790.0	44.0	44.0	7.7	0.0	12.0	30.85	76.35	107.00	2.48
31	2085.0	294.0	294.0	5.6	0.0	16.9	33.13	78.86	100.00	2.89
32	2181.0	97.0	97.0	5.6	0.0	16.9	33.89	79.59	99.90	3.02
33	2265.0	100.0	100.0	6.1	0.0	15.4	34.73	80.78	96.00	3.14

TABLE B15

PRODUCTION HISTORY FOR RUN 15 - Bottom Water Run

[Model II, Continuous Solvent Injection;CSI, OB Press=1500 kPag, Ip=34%, Pp=85% OS depth]

Porosity = 36.0%
Bitumen saturation = 75.0% PV
keff to water = 5.5µm2

Wt. sand pack = 4580.0 g
Wt. glass bead pack = 312.0
Bitumen in place = 687.0 g

Rate = 300 ml/hr
BT Volume = 150.0ml
BT pressure = 182.0kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
0	0.0	0.0	0.0	0.0	—	0.0	0.00	0.00	0.00	0.00
1	49.0	50.0	0.0	0.0	—	0.0	0.00	0.00	68.00	0.07
2	99.0	50.0	0.0	0.0	—	0.0	0.00	0.00	159.00	0.15
3	150.0	50.0	0.0	0.0	—	0.0	0.00	0.00	182.00	0.22
4	206.0	50.5	20.5	26.6	5.5	2.8	0.82	7.30	188.00	0.31
5	254.0	53.0	35.5	23.5	2.1	3.3	2.07	16.62	184.00	0.38
6	304.0	50.0	38.0	18.0	1.8	4.6	3.09	24.13	174.00	0.46
7	348.0	50.5	41.5	18.0	1.2	4.6	4.21	30.86	145.00	0.52
8	397.0	47.5	41.5	15.0	1.0	5.7	5.15	35.94	139.00	0.60
9	443.0	45.0	41.0	13.0	0.8	6.7	5.95	40.26	130.00	0.66
10	495.0	51.0	45.0	14.0	1.0	6.1	6.89	43.85	130.00	0.74
11	545.0	49.0	44.0	18.0	0.6	4.6	8.08	46.44	124.00	0.82
12	598.0	50.0	45.0	16.0	0.7	5.3	9.16	48.65	123.00	0.90
13	652.0	50.0	47.0	18.0	0.4	4.6	10.43	50.53	111.00	0.98
14	702.0	47.5	44.5	19.0	0.4	4.3	11.69	52.07	106.00	1.05
15	748.0	49.0	47.0	24.0	0.2	3.2	13.38	53.64	98.00	1.12
16	788.0	41.0	40.0	22.0	0.1	3.5	14.70	54.88	94.00	1.18
17	838.0	50.0	49.0	16.0	0.1	5.3	15.88	56.51	89.00	1.26

TABLE B15 (CONTINUED)

PRODUCTION HISTORY FOR RUN 15 - Bottom Water Run
[Model II, Continuous Solvent Injection;CSI, OB Press=1500 kPag, Ip=34%, Pp=85% OS depth]

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
18	887.0	53.0	52.5	18.0	0.1	4.6	17.30	58.25	84.00	1.33
19	940.0	54.0	53.5	20.0	0.0	4.0	18.90	59.51	75.00	1.41
20	986.0	49.0	48.5	17.0	0.1	4.9	20.14	60.82	73.00	1.48
21	1035.0	49.0	48.5	16.0	0.1	5.3	21.30	61.88	71.00	1.55
22	1086.0	50.0	49.5	17.0	0.1	4.9	22.56	62.75	67.00	1.63
23	1136.0	49.0	48.5	19.0	0.1	4.3	23.94	63.45	65.00	1.70
24	1189.0	50.5	50.0	15.0	0.1	5.7	25.07	64.20	63.00	1.78
25	1241.0	50.5	50.0	13.0	0.1	6.7	26.04	65.01	61.00	1.86
26	1344.0	100.0	99.0	13.0	0.1	6.7	27.97	66.44	59.00	2.01
27	1392.0	47.5	47.0	12.0	0.1	7.3	28.82	67.12	59.00	2.09
28	1755.0	349.5	346.0	15.0	0.1	5.7	36.60	69.99	52.00	2.63
29	1801.0	50.0	49.5	14.0	0.1	6.1	37.64	70.57	52.00	2.70
30	2170.0	454.0	452.0	12.0	0.0	7.3	45.77	76.90	49.00	3.25
31	2221.0	45.0	45.0	10.0	0.0	9.0	46.44	76.96	48.00	3.33

TABLE B16

PRODUCTION HISTORY FOR RUN 16 - Effect of Well Penetration

[Model II, CSI, OB pressure = 3450 kPag, hb/hw=5.0, kaw=24μm2,Ip=85%, Pp=34% OS depth]

Porosity = 40.0%
Bitumen saturation = 59.0%
keff to water = 1.3μm2

Wt. sand pack = 4550.0 g
Wt. glass bead pack = 558.0 g
Bitumen in place = 669.0 g

Rate = 300 ml/hr
BT Volume = 90.0 ml
BT pressure = 57.0kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
0	0.0	0.0	0.0	0.0	—	0.0	0.00	0.00	0.00	0.00
1	90.0	50.0	0.0	0.0	—	0.0	0.00	0.00	57.00	0.14
2	146.0	51.5	19.0	7.0	24.4	13.3	0.20	12.10	69.20	0.22
3	197.0	50.5	23.5	7.0	16.4	13.3	0.46	20.06	76.00	0.30
4	248.0	51.5	16.5	7.0	30.3	13.3	0.64	22.13	77.20	0.38
5	295.0	48.5	18.5	3.0	54.1	32.3	0.72	24.68	82.00	0.45
6	345.0	53.0	30.0	3.0	25.6	32.3	0.86	29.54	77.20	0.53
7	390.0	50.0	41.0	4.0	5.5	24.0	1.11	36.22	70.80	0.60
8	430.0	45.0	38.0	3.0	6.1	32.3	1.29	41.43	65.00	0.66
9	476.0	50.0	43.0	3.0	5.4	32.3	1.49	46.19	62.00	0.73
10	522.0	50.0	45.0	2.0	5.6	49.0	1.63	50.56	59.00	0.80
11	574.0	55.0	50.5	1.0	8.9	99.0	1.70	54.69	56.20	0.88
12	622.0	50.0	46.5	1.0	7.5	99.0	1.78	57.87	55.00	0.96
13	672.0	53.0	51.0	1.0	3.9	99.0	1.85	61.08	54.00	1.04
14	720.0	49.5	46.0	1.0	7.6	99.0	1.93	63.33	52.40	1.11
15	767.0	49.5	46.0	1.0	7.3	94.8	2.00	65.39	50.00	1.18
16	814.0	50.0	48.0	1.0	4.1	98.0	2.07	67.45	49.00	1.25
17	861.0	50.0	48.5	1.0	3.1	99.0	2.15	69.34	47.00	1.33
18	907.0	50.0	48.5	1.0	3.4	109.2	2.22	71.13	46.00	1.40

TABLE B16 (CONTINUED)

PRODUCTION HISTORY FOR RUN 16 - Effect of Well Penetration
[Model II, CSI, OB pressure = 3450 kPag, hb/hw=5.0, kaw=24μm2,Ip=85%, Pp=34% OS depth]

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
19	951.0	45.5	44.0	1.0	2.9	85.3	2.30	72.41	45.60	1.47
20	1001.0	51.5	51.0	1.0	1.0	98.0	2.37	73.84	44.60	1.54
21	1053.0	52.0	51.5	1.0	1.0	102.0	2.45	75.03	43.80	1.62
22	1101.0	50.5	50.0	1.0	1.0	100.0	2.53	76.26	43.00	1.70
23	1146.0	50.0	49.5	1.0	1.0	99.0	2.60	77.54	42.60	1.77
24	1196.0	50.0	49.5	1.0	1.0	97.0	2.68	78.39	42.00	1.84
25	1249.0	51.0	50.5	1.0	1.1	112.5	2.75	79.08	40.00	1.92
26	1293.0	45.0	44.5	1.0	0.5	44.4	2.90	79.75	39.20	1.99
27	1392.0	99.0	98.0	1.0	1.0	100.0	3.05	81.05	38.60	2.14
28	1487.0	98.0	97.0	1.0	0.5	47.5	3.36	82.26	37.60	2.29
29	1679.0	200.0	200.0	1.0	0.0	199.0	3.51	84.71	35.80	2.59
30	1785.0	100.0	100.0	1.0	0.0	203.1	3.59	85.25	36.00	2.75
31	1820.0	49.0	49.0	1.0	—	—	3.59	86.30	36.00	2.80

TABLE B17

PRODUCTION HISTORY FOR RUN 17 - Effect of Well Penetration

[Model II, OB pressure=3450 kPag, CSI, hb/hw=5.0, kaw=24μm2, Ip=34% , Pp=85% OS depth]

Porosity = 39%
Bitumen saturation = 56%
keff to water = 1.2μm2

Wt. sand pack = 4508.0 g
Wt. glass bead pack = 790.0 g
Bitumen in place = 649.0 g

Rate = 300 ml/hr
BT Volume = 245.0 ml
BT pressure = 62.0kPag.

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
0	0.0	0.0	0.0	0.0	—	0.0	0.00	0.00	0.00	0.00
1	82.0	50.0	0.0	0.0	—	0.0	0.00	0.00	42.00	0.13
2	129.0	50.0	0.0	0.0	—	0.0	0.00	0.00	39.60	0.20
3	189.0	50.0	0.0	0.0	—	0.0	0.00	0.00	52.80	0.30
4	245.0	44.5	0.0	0.0	—	0.0	0.00	0.00	62.00	0.39
5	295.0	51.5	43.0	13.0	1.5	6.7	0.89	12.68	60.40	0.47
6	341.0	50.0	44.0	12.0	1.1	7.3	1.73	22.33	58.20	0.54
7	388.0	50.0	43.0	12.0	1.4	7.3	2.54	29.37	55.60	0.62
8	436.0	53.0	48.0	13.0	0.8	6.7	3.53	35.72	50.60	0.69
9	482.0	50.0	46.0	13.0	0.7	6.7	4.48	40.61	50.60	0.77
10	530.0	50.5	47.0	14.0	0.5	6.1	5.53	44.56	49.00	0.84
11	577.0	48.5	45.5	7.0	0.9	13.3	6.03	48.26	48.60	0.92
12	627.0	53.0	50.0	7.0	0.9	13.3	6.59	51.83	46.00	1.00
13	678.0	50.0	47.0	7.0	0.9	13.3	7.11	54.38	45.70	1.08
14	727.0	50.0	46.0	10.0	0.9	9.0	7.84	56.41	44.40	1.15
15	774.0	49.5	47.0	8.0	0.7	11.5	8.44	58.57	43.80	1.23
16	824.0	50.0	47.5	5.0	1.1	19.0	8.82	60.49	43.40	1.31
17	875.0	47.5	46.0	5.0	0.7	19.0	9.18	61.96	43.00	1.39
18	920.0	45.0	43.5	5.0	0.7	19.0	9.53	63.42	41.00	1.46

TABLE B17 (CONTINUED)

PRODUCTION HISTORY FOR RUN 17 - Effect of Well Penetration
[Model II, OB pressure=3450 kPag, CSI, hb/hw=5.0, kaw=24μm2, Ip=34% , Pp=85% OS depth]

SAMPLE #	CUM SOLV inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	WOR — (cm3/cm3)	SOR — (cm3/cm3)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	SOLV inj (HCPV)
19	966.0	46.5	45.0	5.0	0.7	19.0	9.88	64.83	41.00	1.53
20	1017.0	50.0	47.5	5.0	1.1	19.0	10.26	66.01	40.80	1.61
21	1066.0	50.0	49.0	5.0	0.4	19.0	10.65	67.35	40.40	1.69
22	1116.0	51.5	50.5	5.0	0.4	19.0	11.05	68.63	40.00	1.77
23	1171.0	50.0	48.0	5.0	0.8	19.0	11.43	69.30	40.00	1.86
24	1218.0	50.0	48.0	5.0	0.8	19.0	11.81	70.37	40.00	1.93
25	1268.0	52.0	50.5	5.0	0.6	19.0	12.21	71.38	39.80	2.01
26	1319.0	50.5	49.5	5.0	0.4	19.0	12.61	72.18	39.60	2.09
27	1373.0	52.5	51.5	5.0	0.4	19.0	13.01	72.91	38.60	2.18
28	1423.0	50.0	49.0	5.0	0.4	19.0	13.40	73.62	38.80	2.26
29	1461.0	50.0	49.0	5.0	0.4	19.0	13.79	74.89	38.60	2.32
30	1530.0	60.0	59.0	5.0	0.3	19.0	14.26	75.17	38.60	2.43
31	1587.0	57.0	56.0	5.0	0.4	19.0	14.70	75.83	38.40	2.52
32	1615.0	45.0	44.0	5.0	0.5	19.0	15.05	77.10	38.20	2.56

TABLE B18

PRODUCTION HISTORY FOR RUN 18 - Water Alternating Solvent Run

[Model II, OB pressure=3450 kPag, Multiple Slug Run, hb/hw=5.0, kaw=24μm2, Ip=34% , Pp=85% OS depth]

Porosity = 39.5%
Bitumen saturation = 59%
keff to water = 1.2μm2

Wt. sand pack = 4519.0 g
Wt. glass bead pack = 775.0 g
Bitumen in place = 696.0 g

Rate = 300 ml/hr
BT Volume = 238.0 ml
BT pressure = 53.4 kPag.

SAMPLE #	CUM FLUID inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	FLUID inj (HCPV)	SOLV inj (HCPV)	WHCR — (cm3/cm3)	FLUID inj (type)
0	0.0	0.0	0.0	0.0	0	0	0	0	0.00	—	Solv
1	78.0	49.5	0.0	0.0	0.00	0.00	35.20	0.12	0.12	—	Solv
2	137.0	50.0	0.0	0.0	0.00	0.00	44.20	0.20	0.20	—	Solv
3	192.0	50.0	0.0	0.0	0.00	0.00	50.40	0.28	0.28	—	Solv
4	238.0	43.5	0.0	0.0	0.00	0.00	53.40	0.35	0.35	—	Solv
5	290.0	50.5	38.0	20.0	1.12	10.48	49.60	0.43	0.43	0.3	Solv
6	332.0	45.0	37.0	8.0	1.56	19.41	45.00	0.49	0.49	0.2	Solv
7	395.0	50.0	41.5	9.0	2.11	30.78	41.00	0.58	0.49	0.2	Water
8	439.0	49.0	41.5	5.0	2.42	42.66	33.00	0.65	0.49	0.2	Water
9	489.0	52.0	13.0	13.0	2.67	46.07	28.00	0.72	0.49	3.0	Water
10	536.0	52.0	8.0	14.0	2.84	48.14	25.80	0.79	0.49	5.5	Water
11	580.0	45.0	6.0	20.0	3.01	49.58	24.00	0.86	0.49	6.5	Water
12	634.0	49.0	8.5	13.0	3.18	44.56	34.00	0.94	0.57	4.8	Solv
13	694.0	49.0	7.0	11.0	3.29	39.97	50.00	1.03	0.66	6.0	Solv
14	755.0	55.0	34.0	6.0	3.59	41.46	55.40	1.12	0.75	0.6	Solv
15	804.0	49.5	44.5	14.0	4.52	44.69	54.80	1.19	0.82	0.1	Solv
16	851.0	49.0	44.0	8.0	5.04	47.92	54.20	1.26	0.89	0.1	Solv
17	921.0	51.0	48.0	4.0	5.32	49.78	53.20	1.36	1.00	0.1	Solv
18	968.0	49.0	46.0	2.0	5.46	56.48	47.20	1.43	1.00	0.1	Water

TABLE B18 (CONTINUED)

PRODUCTION HISTORY FOR RUN 18 - Water Alternating Solvent Run

[Model II, OB pressure=3450 kPag, Multiple Slug Run, hb/hw=5.0, kaw=24μm2, Ip=34% , Pp=85% OS depth]

SAMPLE #	CUM FLUID inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	FLUID inj (HCPV)	SOLV inj (HCPV)	WHCR — (cm3/cm3)	FLUID inj (type)
19	1016.0	51.0	46.0	3.0	5.66	63.11	40.20	1.50	1.00	0.1	Water
20	1063.0	50.0	13.0	3.0	5.72	64.98	33.80	1.57	1.00	2.8	Water
21	1109.0	50.0	13.0	4.0	5.80	66.84	30.80	1.64	1.00	2.8	Water
22	1153.0	45.0	5.0	5.0	5.83	67.54	29.00	1.71	1.00	8.0	Water
23	1213.0	50.5	6.5	6.0	5.89	68.45	27.60	1.79	1.00	6.8	Water
24	1250.0	52.0	7.0	6.0	5.95	69.43	26.20	1.85	1.00	6.4	Water
25	1306.0	53.5	7.5	10.0	6.06	65.02	37.00	1.93	1.08	6.1	Solv
26	1363.0	49.5	8.5	11.0	6.20	61.27	53.00	2.02	1.16	4.8	Solv
27	1422.0	49.0	30.0	5.0	6.42	60.36	61.40	2.10	1.25	0.6	Solv
28	1474.0	55.0	50.5	1.0	6.50	62.44	61.20	2.18	1.33	0.1	Solv
29	1522.0	49.5	47.0	1.0	6.57	64.19	61.00	2.25	1.40	0.1	Solv
30	1574.0	50.0	46.0	1.0	6.64	65.41	60.80	2.33	1.47	0.1	Solv
31	1624.0	52.0	48.0	1.0	6.71	70.18	54.00	2.40	1.47	0.1	Water
32	1672.0	50.0	45.0	1.0	6.77	74.65	45.60	2.47	1.47	0.1	Water
33	1715.0	52.0	17.0	1.0	6.80	76.33	39.00	2.54	1.47	2.1	Water
34	1764.0	52.0	10.0	4.0	6.86	77.30	35.00	2.61	1.47	4.2	Water

TABLE B19

PRODUCTION HISTORY FOR RUN 19 - 1.0% Surfactant Alternating Solvent Run

[Model II, OB pressure=3450 kPag, Multiple Slug Run, hb/hw=5.0, kaw=24μm2, Ip=34% , Pp=85% OS depth]

Porosity = 39.4%
Bitumen saturation = 58%
keff to water = 1.0μm2

Wt. sand pack = 4534.0 g
Wt. glass bead pack = 805.0 g
Bitumen in place = 676.0 g

Rate = 300 ml/hr
BT Volume = 252.0 ml
BT pressure = 55.2 kPag.

SAMPLE #	CUM FLUID inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	FLUID inj (HCPV)	SOLV inj (HCPV)	WHCR — (cm3/cm3)	FLUID inj (type)
0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	—	Solv
1	59.0	50.0	0.0	0.0	0.00	0.00	37.80	0.09	0.09	—	Solv
2	111.0	50.5	0.0	0.0	0.00	0.00	45.20	0.17	0.17	—	Solv
3	162.0	50.0	0.0	0.0	0.00	0.00	49.80	0.25	0.25	—	Solv
4	215.0	49.5	0.0	0.0	0.00	0.00	55.20	0.33	0.33	—	Solv
5	252.0	30.0	0.0	0.0	0.00	0.00	55.20	0.38	0.38	—	Solv
6	305.0	49.5	33.5	15.9	0.81	9.24	56.20	0.46	0.46	0.48	Solv
7	333.0	27.5	22.5	16.0	1.36	14.14	53.00	0.51	0.51	0.22	Solv
8	381.0	50.5	43.5	9.7	2.00	25.93	49.50	0.58	0.51	0.16	1% Surf
9	431.0	51.5	45.0	8.5	2.59	38.30	42.60	0.66	0.51	0.14	1% Surf
10	478.0	50.0	18.0	8.5	2.82	43.24	36.80	0.73	0.51	1.78	1% Surf
11	523.0	47.0	6.0	8.5	2.90	44.89	34.80	0.80	0.51	6.83	1% Surf
12	573.0	51.5	4.5	8.5	2.96	46.13	34.40	0.87	0.51	10.44	1% Surf
13	611.0	40.0	5.0	8.5	3.02	47.50	35.20	0.93	0.51	7.00	1% Surf
14	662.0	52.5	3.5	8.5	3.07	42.03	52.60	1.01	0.59	14.00	Solv
15	721.0	52.5	5.0	8.5	3.13	37.46	82.60	1.10	0.68	9.50	Solv
16	776.0	49.5	15.5	13.9	3.46	36.00	98.00	1.18	0.76	2.19	Solv
17	826.0	51.0	43.0	12.2	4.26	39.61	95.40	1.26	0.84	0.19	Solv
18	876.0	51.0	46.0	12.2	5.11	43.05	87.40	1.34	0.91	0.11	Solv

TABLE B19 (CONTINUED)

PRODUCTION HISTORY FOR RUN 19 - 1.0% Surfactant Alternating Solvent Run
[Model II, OB pressure=3450 kPag, Multiple Slug Run, hb/hw=5.0, kaw=24μm2, lp=0.34 , Pp=.85 OS depth]

SAMPLE #	CUM FLUID inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	FLUID inj (HCPV)	SOLV inj (HCPV)	WHCR — (cm3/cm3)	FLUID inj (type)
19	923.0	50.0	46.0	8.4	5.70	46.45	82.00	1.41	0.98	0.09	Solv
20	967.0	46.5	43.0	8.2	6.24	52.57	79.20	1.47	0.98	0.08	1% Surf
21	1015.0	49.0	45.0	6.4	6.68	59.10	67.20	1.55	0.98	0.09	1% Surf
22	1065.0	51.0	20.0	9.9	6.98	61.89	63.40	1.62	0.98	1.55	1% Surf
23	1115.0	51.5	6.5	9.9	7.08	62.80	65.00	1.70	0.98	6.92	1% Surf
24	1166.0	50.5	3.0	9.9	7.13	63.22	68.20	1.78	0.98	15.83	1% Surf
25	1217.0	50.5	2.0	9.9	7.16	58.84	91.20	1.86	1.06	24.25	Solv
26	1267.0	49.5	12.5	9.9	7.34	56.41	109.40	1.93	1.14	2.96	Solv
27	1316.0	50.0	28.0	11.0	7.81	56.07	110.20	2.01	1.21	0.79	Solv
28	1364.0	50.0	45.0	12.5	8.67	57.55	97.00	2.08	1.29	0.11	Solv
29	1411.0	52.0	48.5	8.3	9.29	59.50	91.20	2.15	1.36	0.07	Solv
30	1459.0	50.0	46.5	7.6	9.82	61.04	84.80	2.22	1.43	0.08	Solv
31	1509.0	51.0	48.0	7.7	10.39	65.76	87.00	2.30	1.43	0.06	1% Surf
32	1559.0	51.0	42.0	10.1	11.03	69.79	77.00	2.38	1.43	0.21	1% Surf
33	1619.0	54.0	9.0	10.2	11.17	70.65	89.00	2.47	1.43	5.00	1% Surf
34	1669.0	58.0	18.0	10.2	11.45	72.37	87.00	2.54	1.43	2.22	1% Surf

TABLE B20

PRODUCTION HISTORY FOR RUN 20 - 0.1% Surfactant Alternating Solvent Run
[Model II, OB pressure=3450 kPag, Multiple Slug Run, hb/hw=5.0, kaw=24µm2, Ip=34% , Pp=85% OS depth]

Porosity = 37.5%
Bitumen saturation = 61.3%
keff to water = 0.6µm2

Wt. sand pack = 4431.0 g
Wt. glass bead pack = 938.0 g
Bitumen in place = 682.0 g

Rate = 300 ml/hr
BT Volume = 225.0 ml
BT pressure = 62.0 kPag.

SAMPLE #	CUM FLUID inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT in HC (vol %)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	FLUID inj (HCPV)	SOLV inj (HCPV)	WHCR — (cm3/cm3)	FLUID inj (type)
0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	—	Solv
1	74.0	50.0	0.0	0.0	0.00	0.00	70.00	0.12	0.12	—	Solv
2	131.0	50.0	0.0	0.0	0.00	0.00	57.80	0.20	0.20	—	Solv
3	170.0	50.0	0.0	0.0	0.00	0.00	55.40	0.27	0.27	—	Solv
4	225.0	55.0	0.0	0.0	0.00	0.00	57.00	0.35	0.35	—	Solv
5	275.0	50.0	0.0	0.0	0.00	0.00	62.00	0.43	0.43	—	Solv
6	327.0	55.0	42.5	11.3	0.75	11.53	51.80	0.51	0.51	0.29	Solv
7	360.0	34.5	30.5	17.0	1.56	17.50	49.20	0.56	0.56	0.13	Solv
8	410.0	51.0	45.5	7.0	2.05	29.26	43.40	0.64	0.56	0.12	.1% Surf
9	462.0	51.0	45.0	6.1	2.48	41.00	37.20	0.72	0.56	0.13	.1% Surf
10	508.0	50.0	30.0	4.6	2.70	48.95	31.20	0.79	0.56	0.67	.1% Surf
11	582.0	75.5	17.0	7.7	2.90	53.30	29.00	0.91	0.56	3.44	.1% Surf
12	623.0	51.0	6.0	11.7	3.01	49.17	43.80	0.97	0.63	7.50	Solv
13	685.0	51.5	6.5	11.7	3.13	43.83	49.80	1.07	0.72	6.92	Solv
14	742.0	53.0	7.5	11.7	3.27	40.30	52.00	1.16	0.81	6.07	Solv
15	797.0	52.0	47.5	10.7	4.06	43.82	57.20	1.24	0.90	0.09	Solv
16	849.0	52.0	47.0	10.3	4.82	46.91	54.80	1.32	0.98	0.11	Solv
17	897.0	51.0	46.5	7.7	5.37	49.93	52.40	1.40	1.05	0.10	Solv
18	945.0	50.0	46.0	5.9	5.80	52.61	51.20	1.47	1.13	0.09	Solv

TABLE B20

PRODUCTION HISTORY FOR RUN 20 - 0.1% Surfactant Alternating Solvent Run
[Model II, OB pressure=3450 kPag; Multiple Slug Run, hb/hw=5.0, kaw=24μm2, Ip=34% , Pp=85% OS depth]

SAMPLE #	CUM FLUID inj (ml)	INC FLUID prod (ml)	INC HC prod (ml)	VOLUME BIT ⌀ in HC (vol %)	CUM BIT recovery (% OBIP)	CUM SOLV recovery (% solv inj)	PRESS inj (kPa)	FLUID inj (HCPV)	SOLV inj (HCPV)	WHCR — (cm3/cm3)	FLUID inj (type)
19	991.0	48.0	44.0	4.0	6.07	58.45	46.40	1.55	1.13	0.09	.1% Surf
20	1047.0	56.0	52.0	4.6	6.45	65.31	43.40	1.63	1.13	0.08	.1% Surf
21	1089.0	50.0	29.0	4.9	6.67	69.12	30.00	1.70	1.13	0.72	.1% Surf
22	1138.0	50.0	14.0	7.1	6.82	70.92	28.80	1.78	1.13	2.57	.1% Surf
23	1188.0	52.0	10.0	18.5	7.11	72.05	27.00	1.85	1.13	4.20	Solv
24	1239.0	50.0	9.5	18.5	7.39	68.30	42.00	1.93	1.21	4.26	Solv
25	1290.0	50.0	6.0	18.5	7.56	64.67	50.00	2.01	1.29	7.33	Solv
26	1349.0	56.0	13.0	18.5	7.93	61.55	61.20	2.10	1.38	3.31	Solv
27	1397.0	49.5	46.5	7.3	8.46	63.01	58.20	2.18	1.45	0.06	Solv
28	1445.0	51.0	48.0	6.8	8.97	64.49	56.40	2.25	1.53	0.06	Solv
29	1497.0	50.0	46.5	6.4	9.44	65.46	55.00	2.34	1.61	0.08	Solv
30	1547.0	51.0	48.0	5.3	9.83	66.63	54.00	2.41	1.69	0.06	Solv
31	1598.0	57.0	55.0	4.3	10.20	71.50	46.00	2.49	1.69	0.04	.1% Surf
32	1655.0	57.0	54.0	4.4	10.57	76.27	40.00	2.58	1.69	0.06	.1% Surf
33	1702.0	50.0	25.0	4.8	10.76	78.47	29.20	2.66	1.69	1.00	.1% Surf
34	1744.0	51.0	15.0	4.8	10.87	79.79	28.80	2.72	1.69	2.40	.1% Surf

APPENDIX C
PRODUCTION HISTORY OF ALL RUNS IN GRAPHICAL FORM

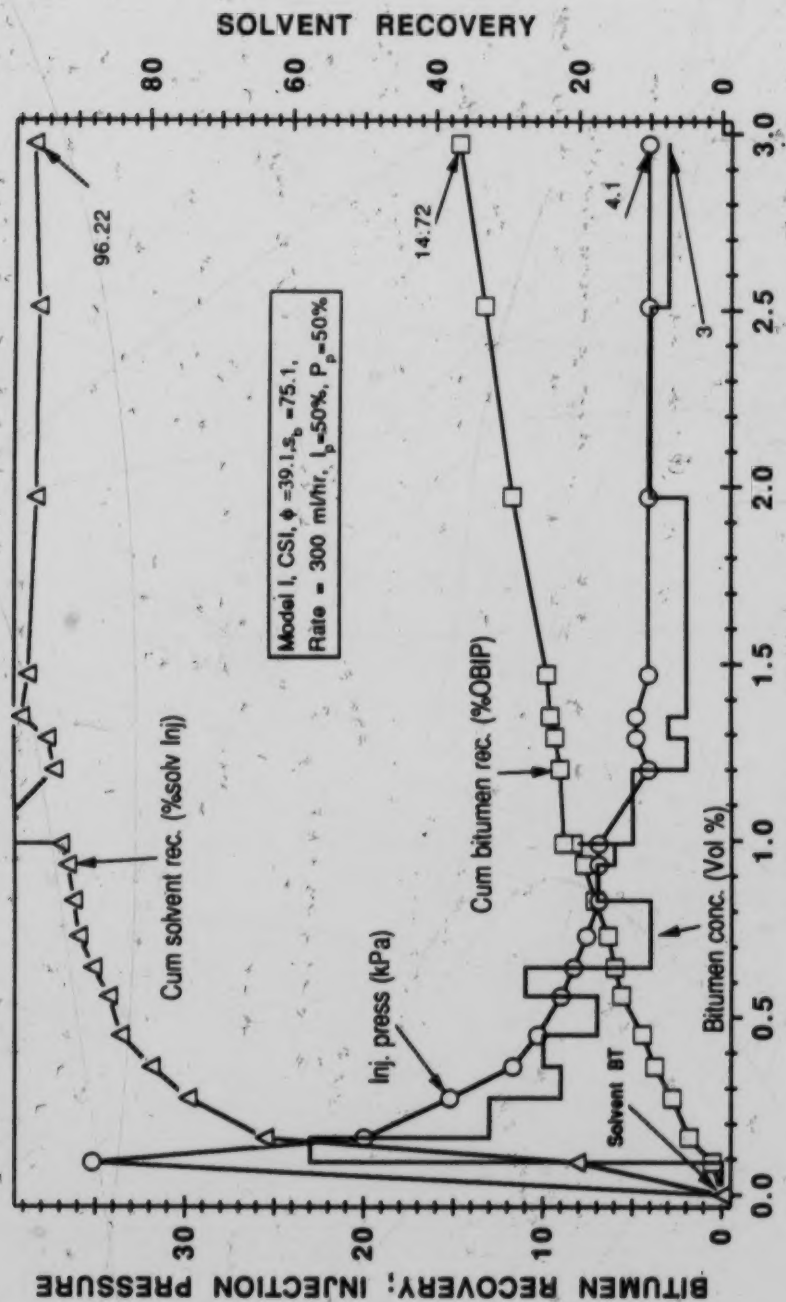


FIGURE C1: PRODUCTION HISTORY FOR RUN 1 - Homogeneous Pack Run.

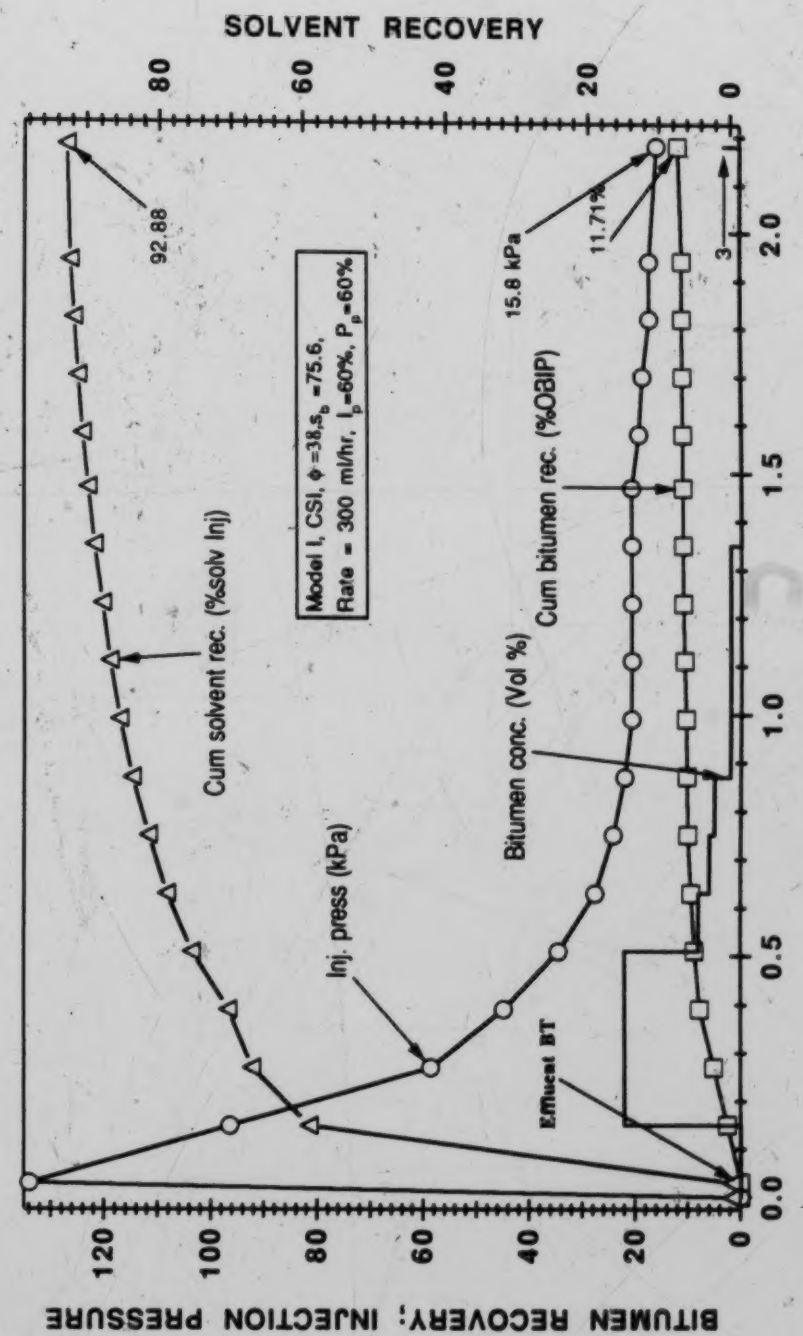


FIGURE C2: PRODUCTION HISTORY FOR RUN 2 - Homogeneous Pack Run.

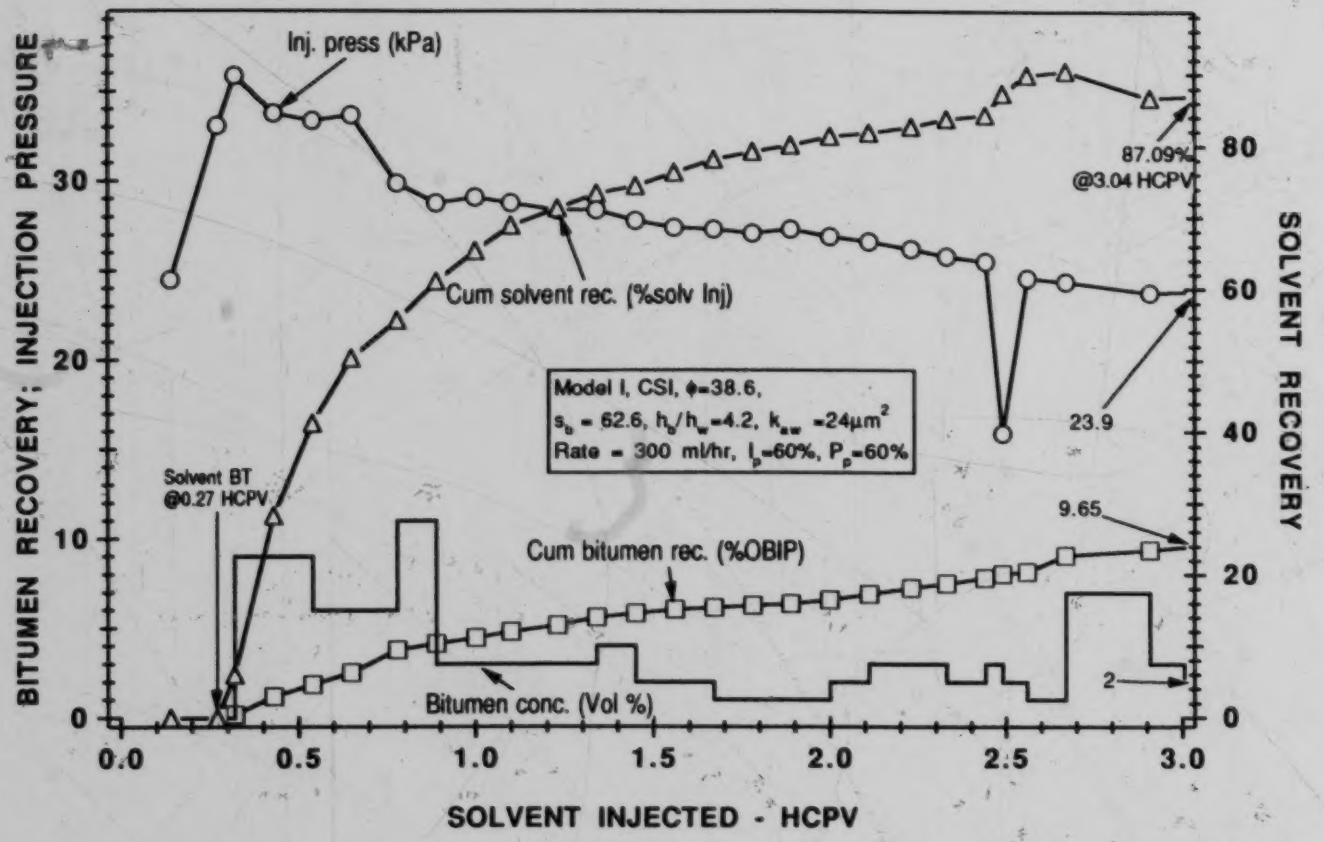


FIGURE C3: PRODUCTION HISTORY FOR RUN 3 - Effect of Bottom Water Thickness.

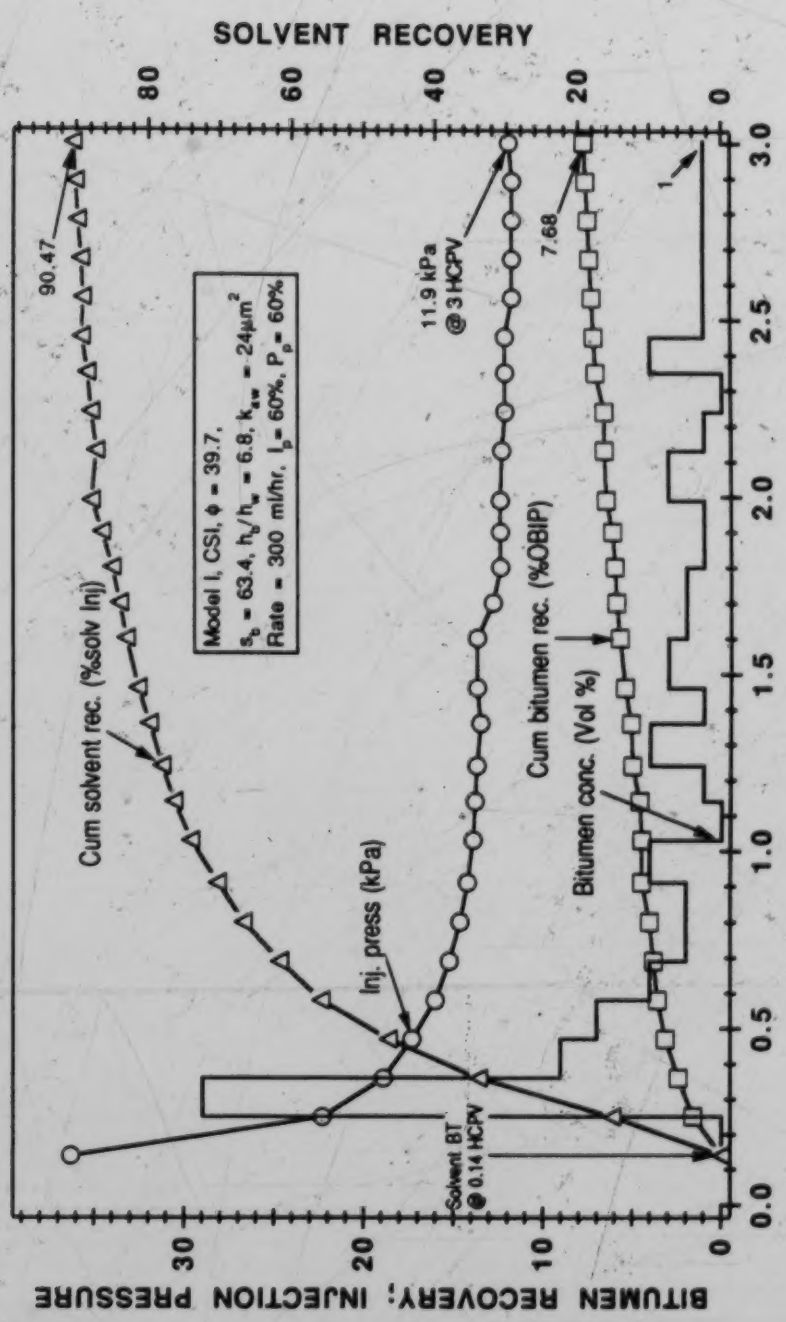


FIGURE C4: PRODUCTION HISTORY FOR RUN 4 - Effect of Bottom Water Thickness.

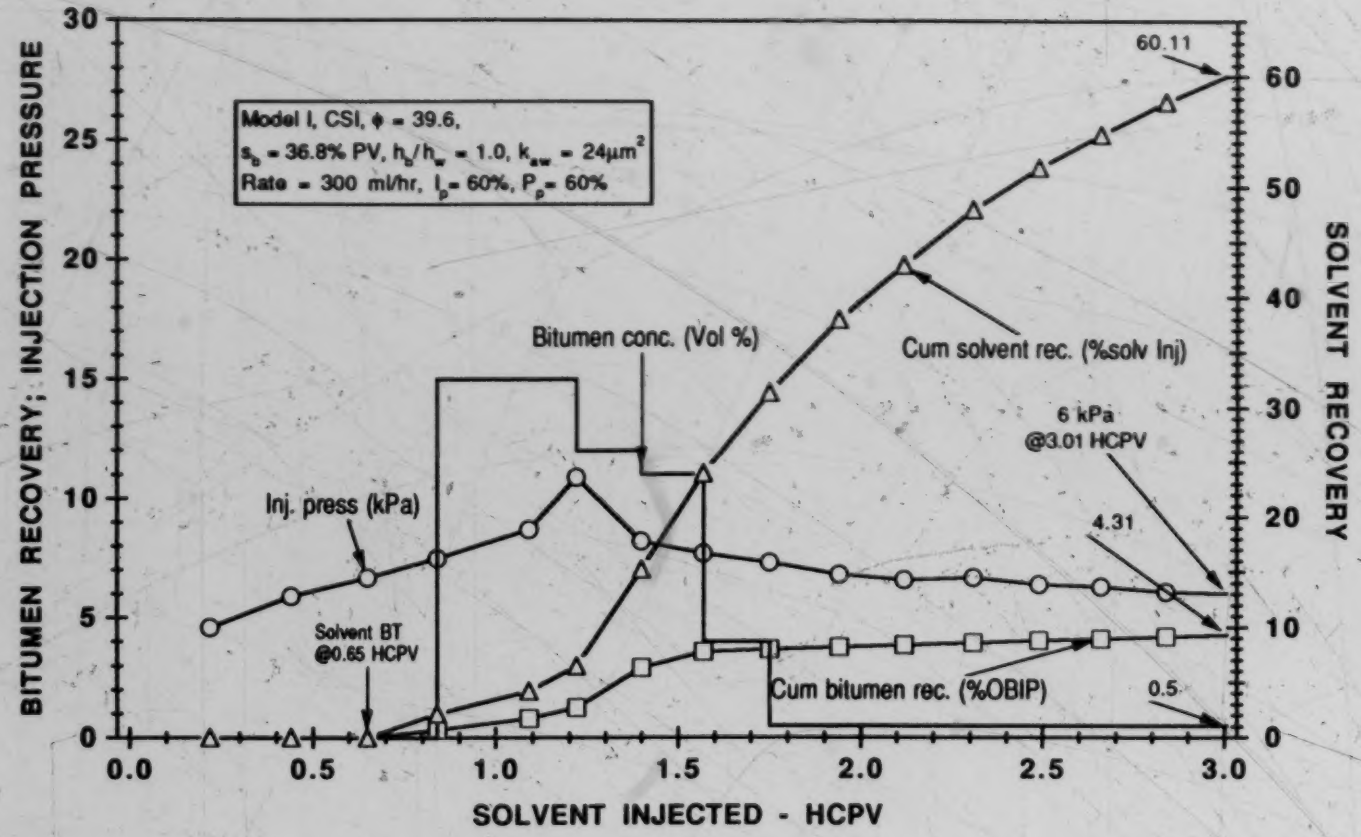


FIGURE C5: PRODUCTION HISTORY FOR RUN 5 - Effect of Bottom Water Thickness.

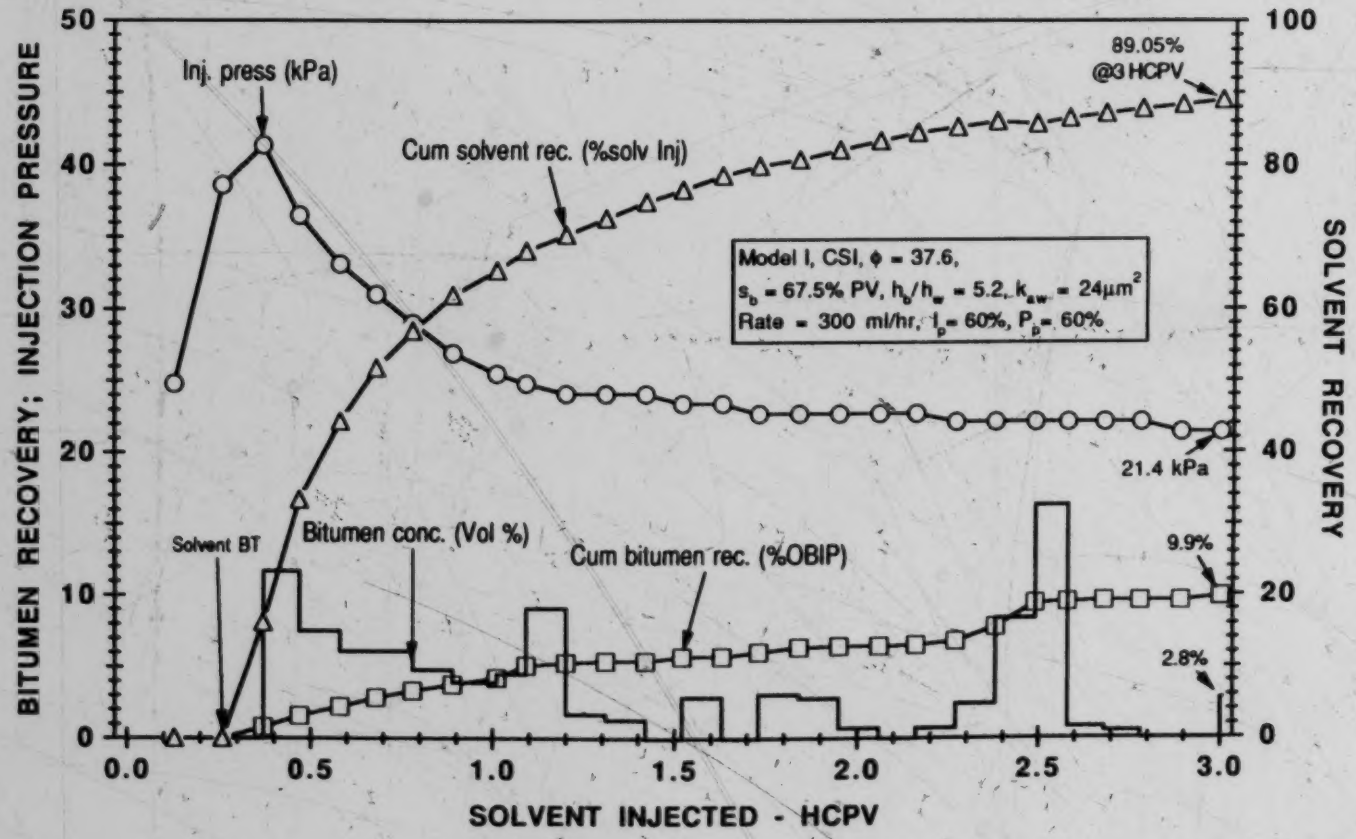


FIGURE C6: PRODUCTION HISTORY FOR RUN 6 - Effect of Bottom Water Thickness.

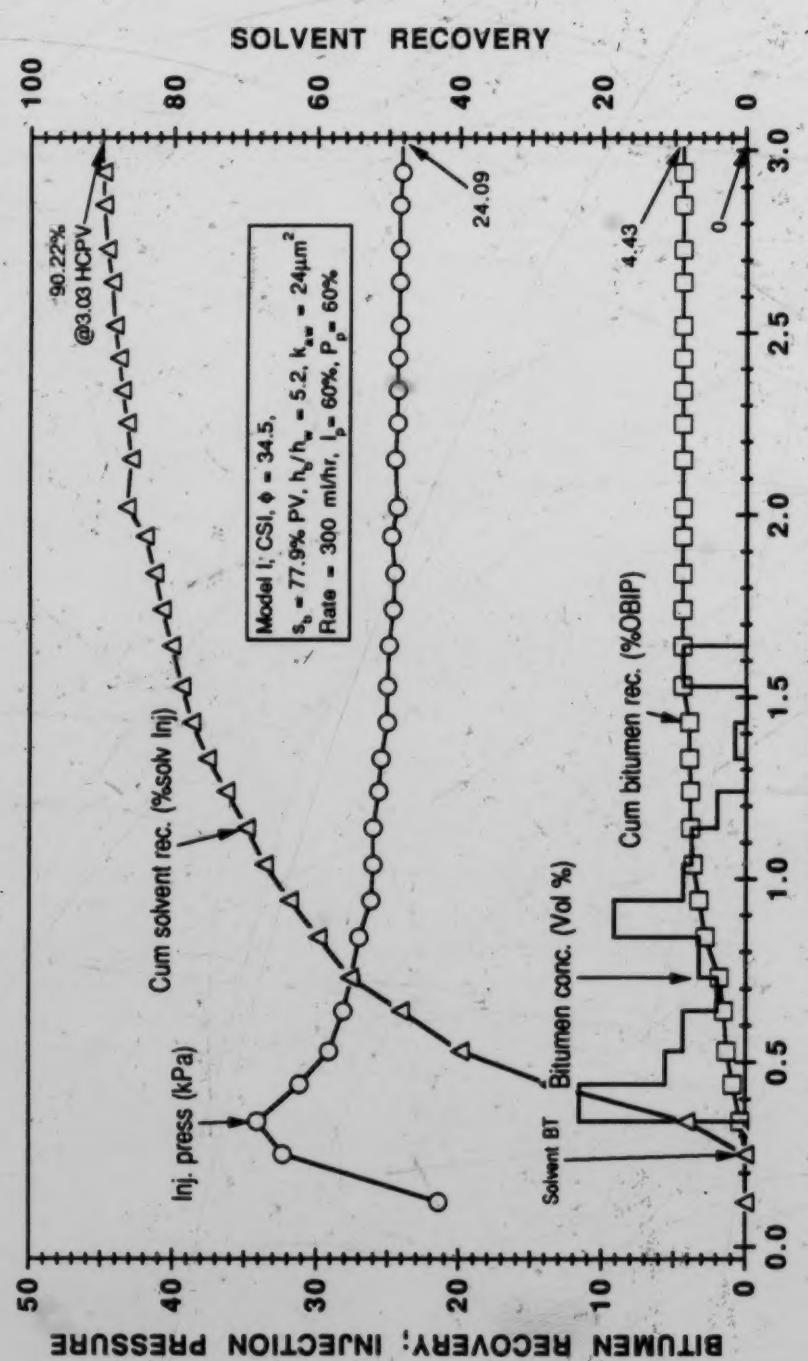


FIGURE C7: PRODUCTION HISTORY FOR RUN 7.

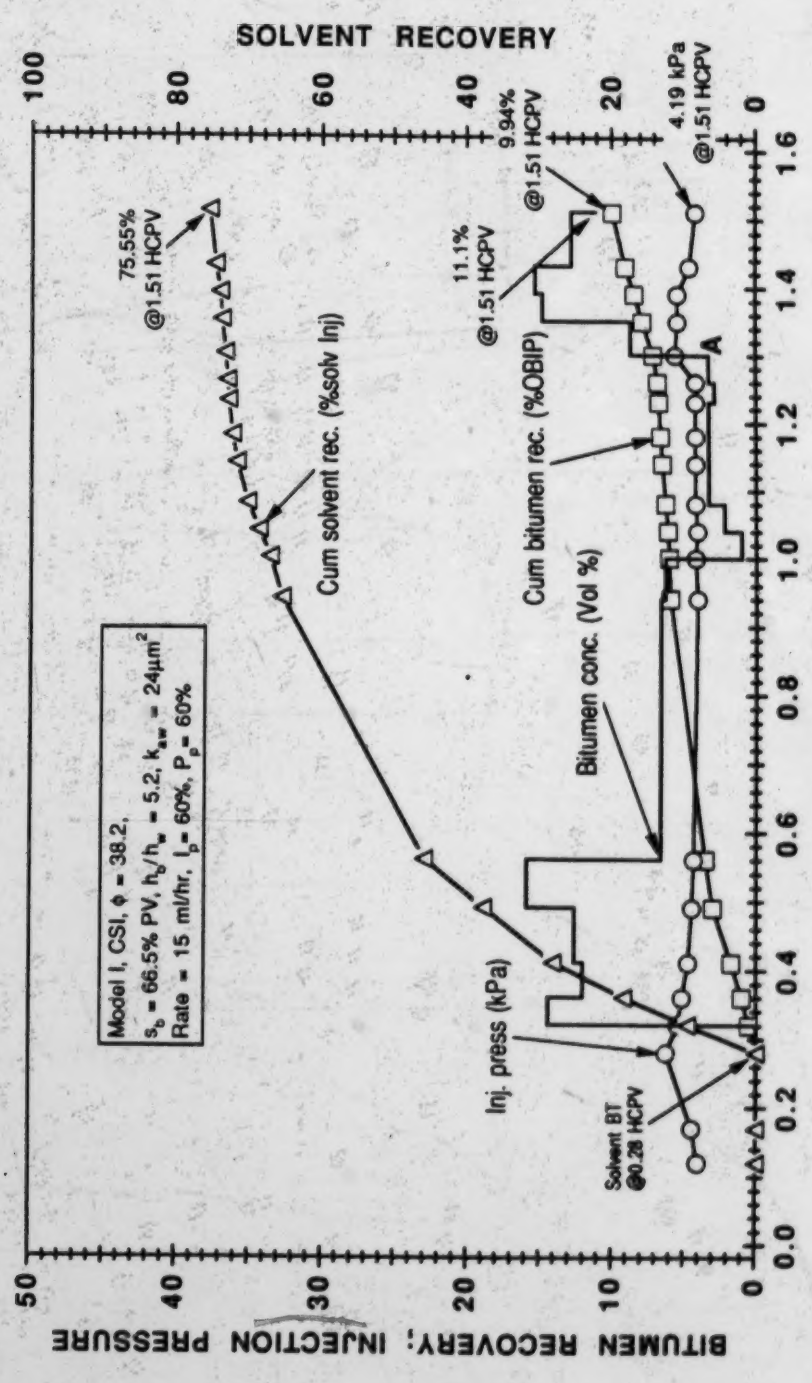

SOLVENT RECOVERY
BITUMEN RECOVERY; INJECTION PRESSURE
SOLVENT INJECTED - HCPV
Model I, CSI, ϕ = 38.2,
s_b = 66.5% PV, h_b/h_w = 5.2, k_{av} = 24μm²
Rate = 15 ml/hr, l_p = 60%, P_p = 60%
75.55% @1.51 HCPV
Cum solvent rec. (%solv Inj)
11.1% @1.51 HCPV
9.94% @1.51 HCPV
Cum bitumen rec. (%OBIP)
4.19 kPa @1.51 HCPV
Bitumen conc. (Vol %)
Inj. press (kPa)
Solvent BT @0.28 HCPV
A

FIGURE C8: PRODUCTION HISTORY FOR RUN 8 - Effect of Rate.

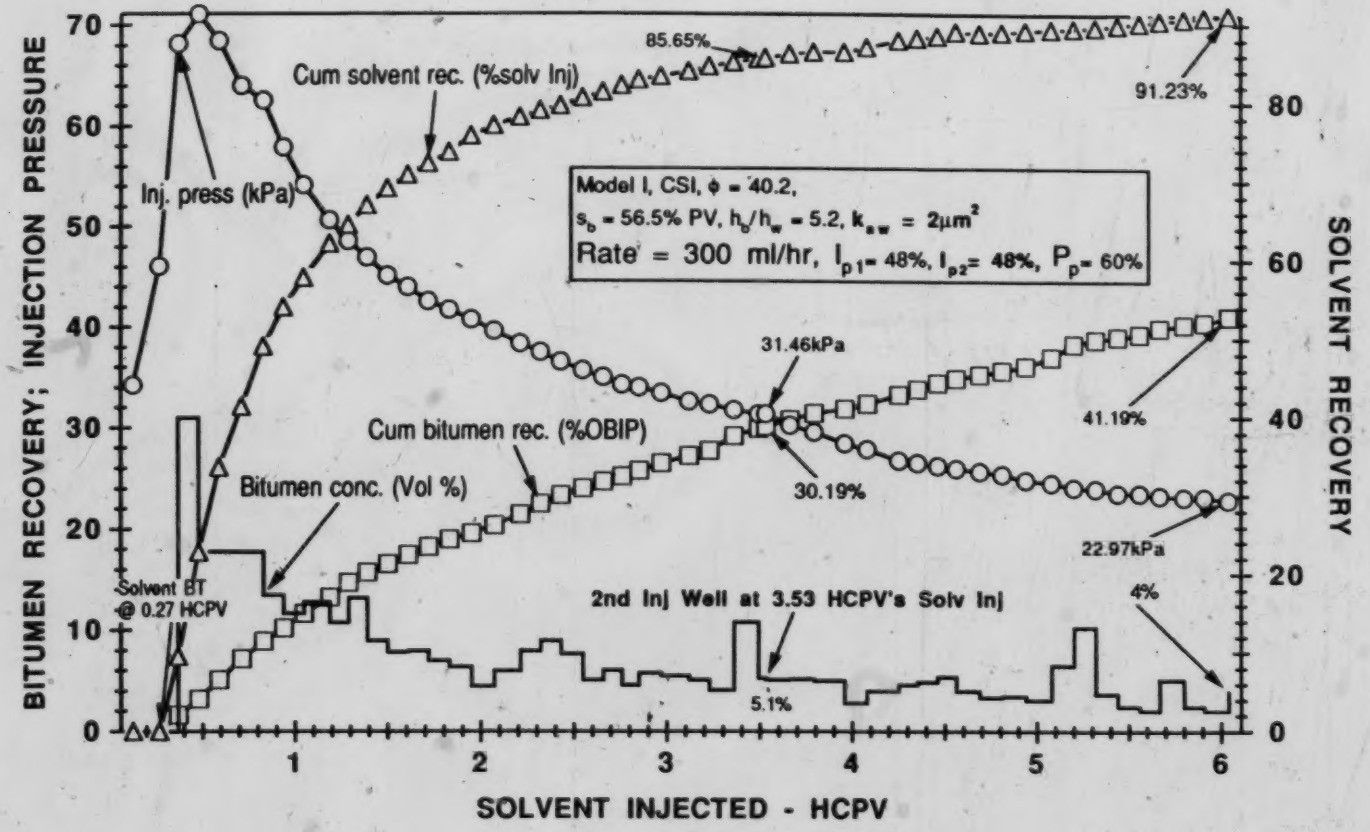


FIGURE C9: PRODUCTION HISTORY FOR RUN 9 - Effect of Bottom Water Permeability and Well Interval

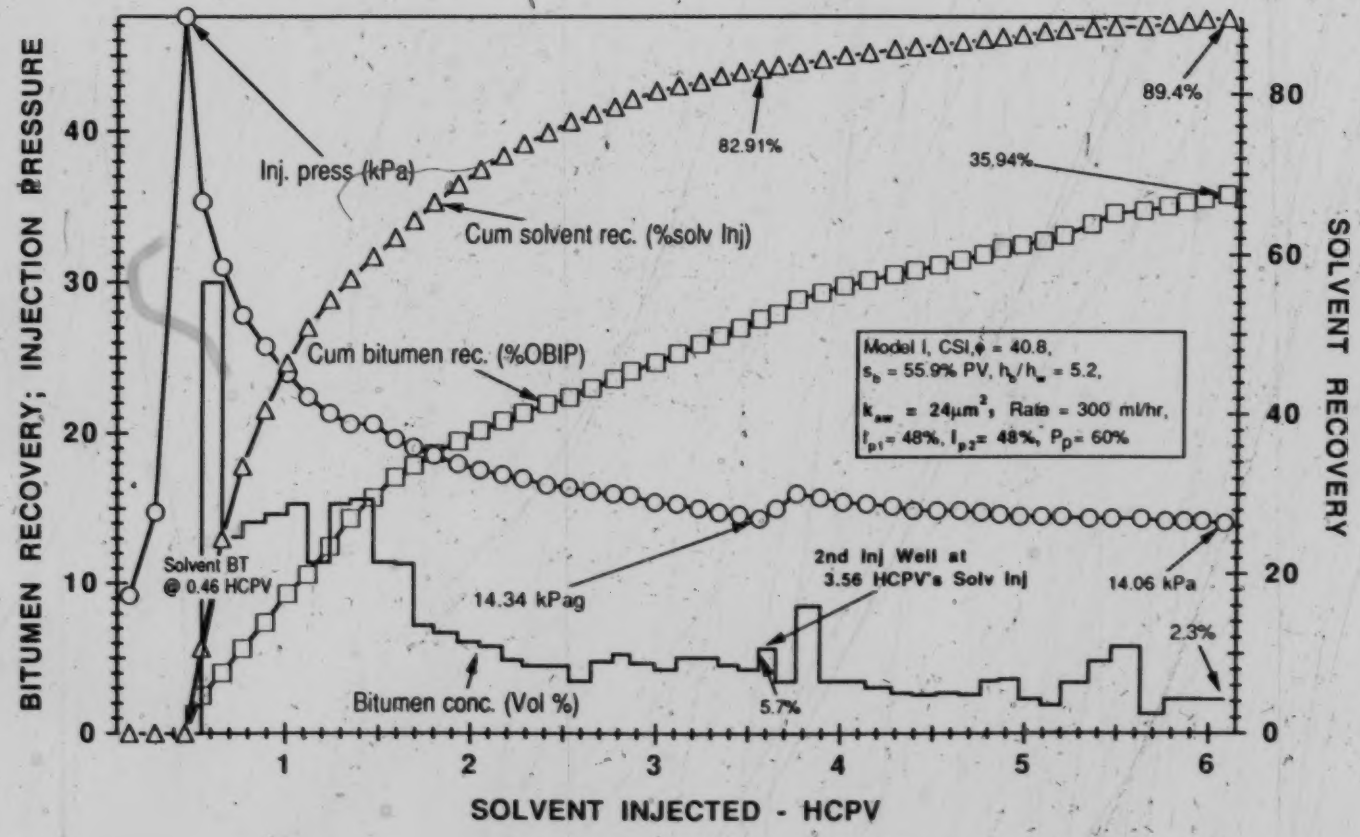


FIGURE C10: PRODUCTION HISTORY FOR RUN 10 - Effect of Bottom Water Permeability and Well Interval.

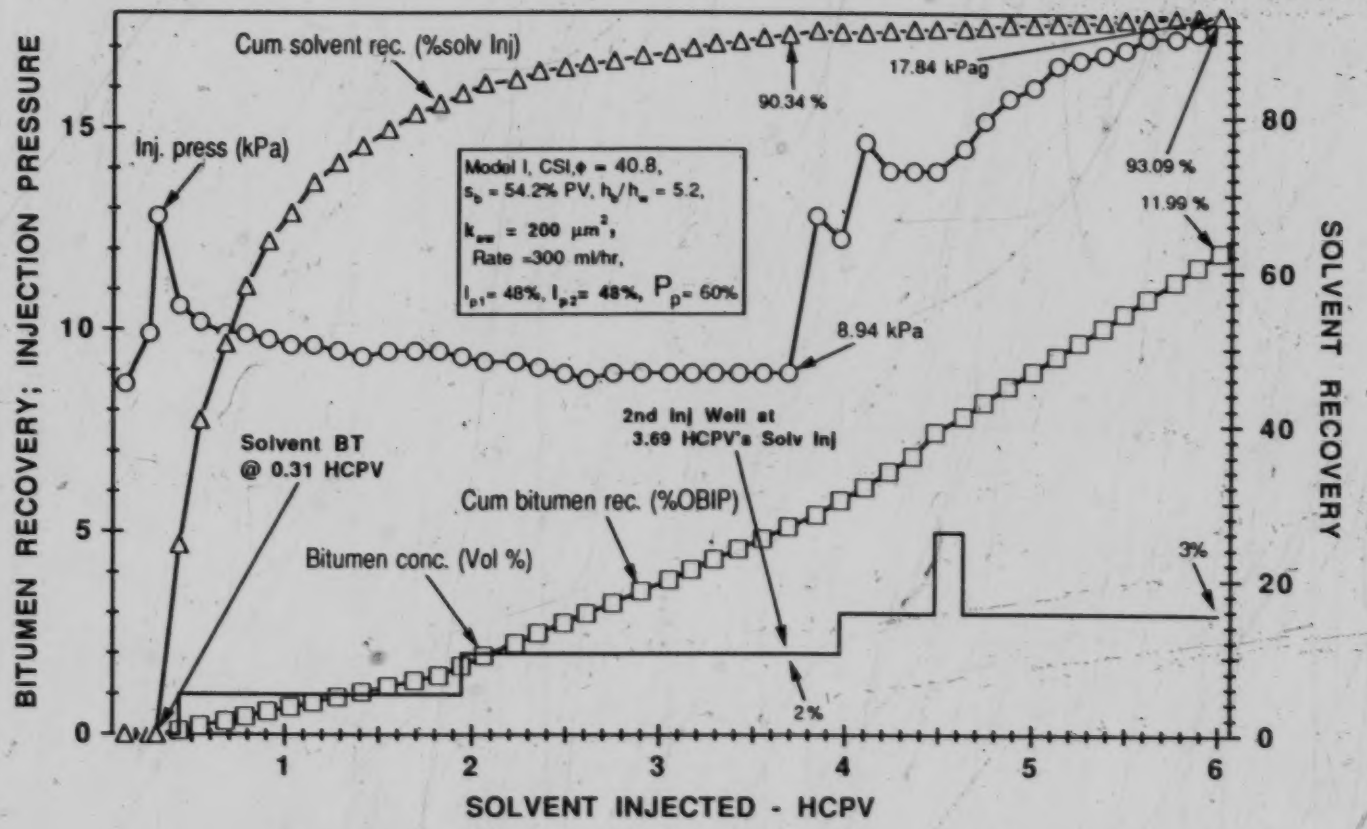


FIGURE C11: PRODUCTION HISTORY FOR RUN 11 - Effect of Bottom Water Permeability and Well Interval.

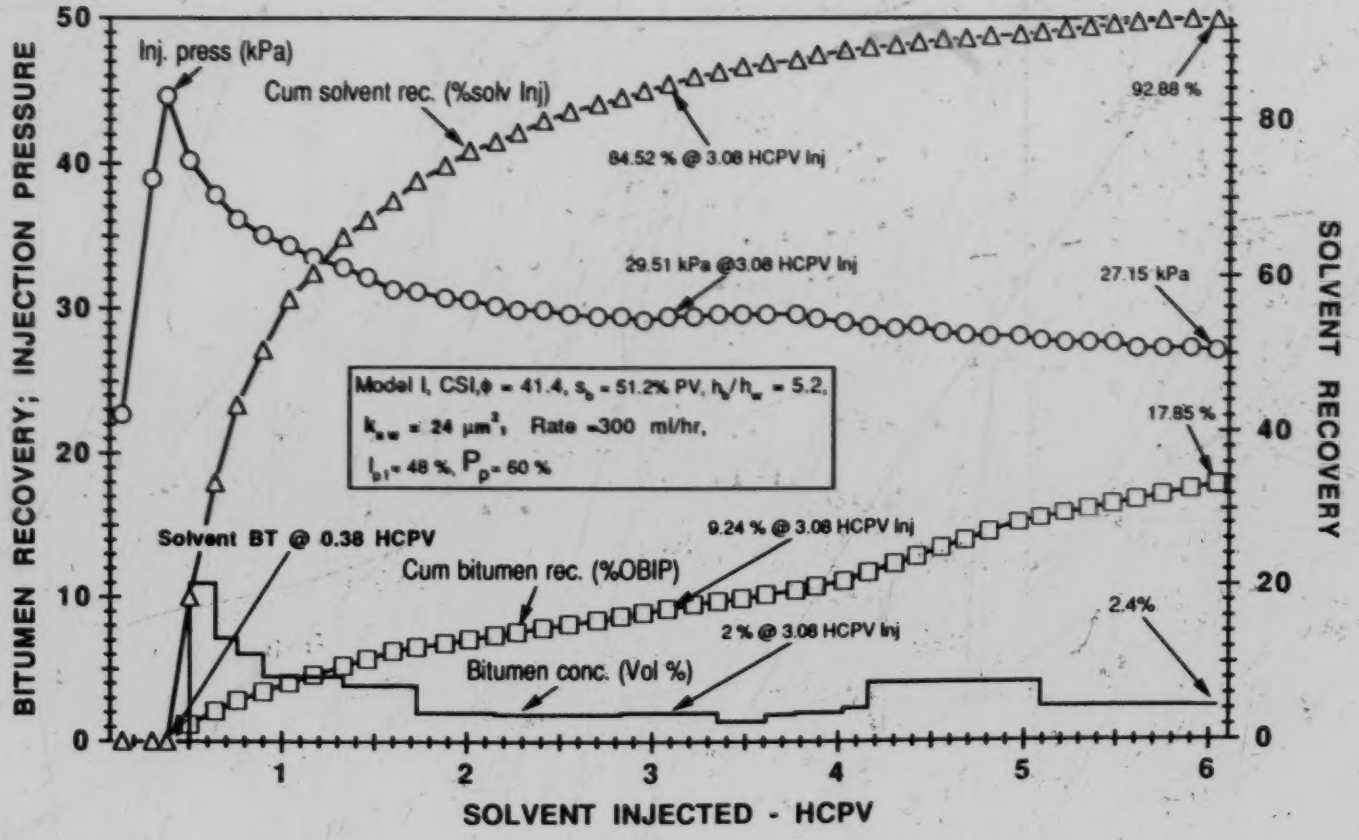


FIGURE C12: PRODUCTION HISTORY FOR RUN 12 - Effect of Well Interval.

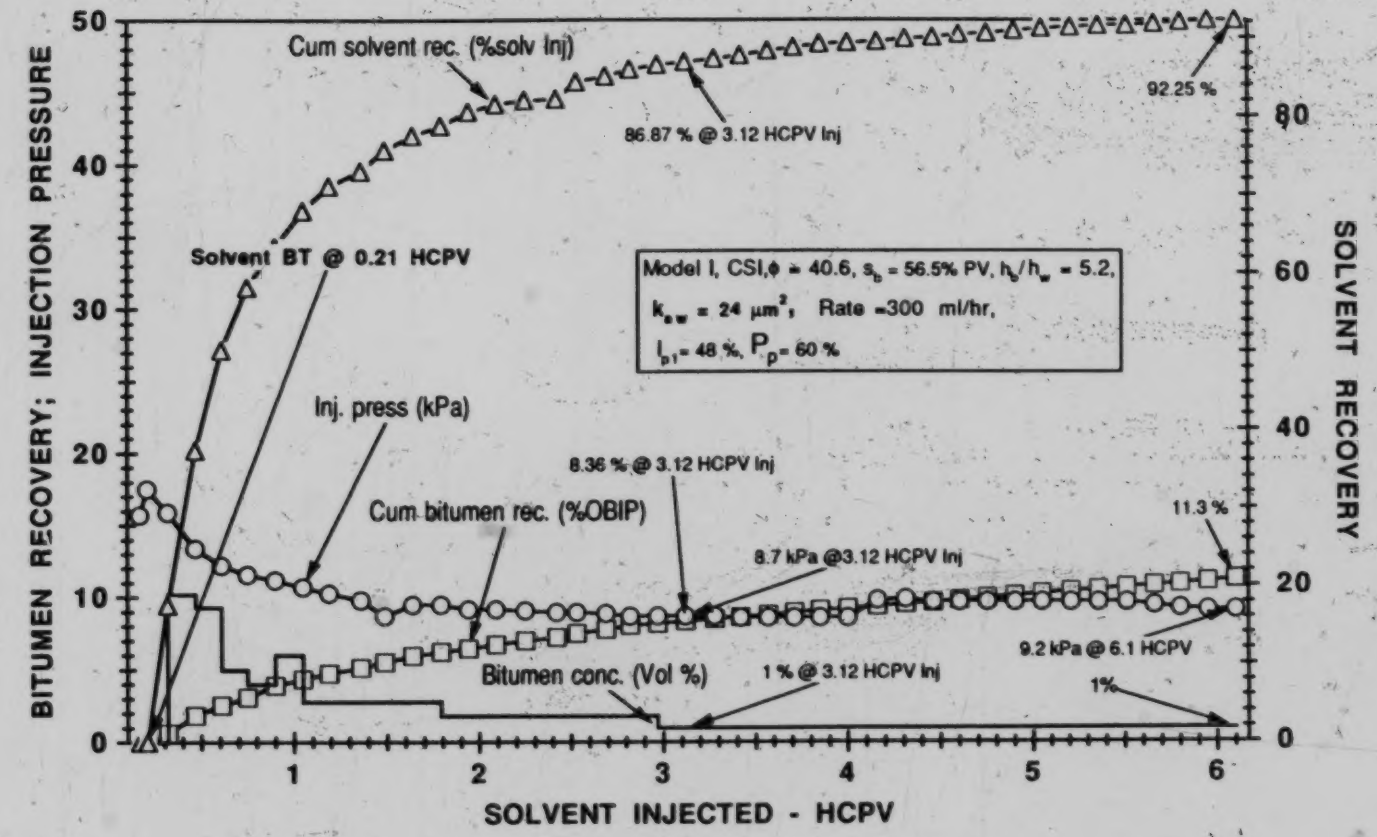


FIGURE C13: PRODUCTION HISTORY FOR RUN 13 - Effect of Well Interval Repeat Base Run.

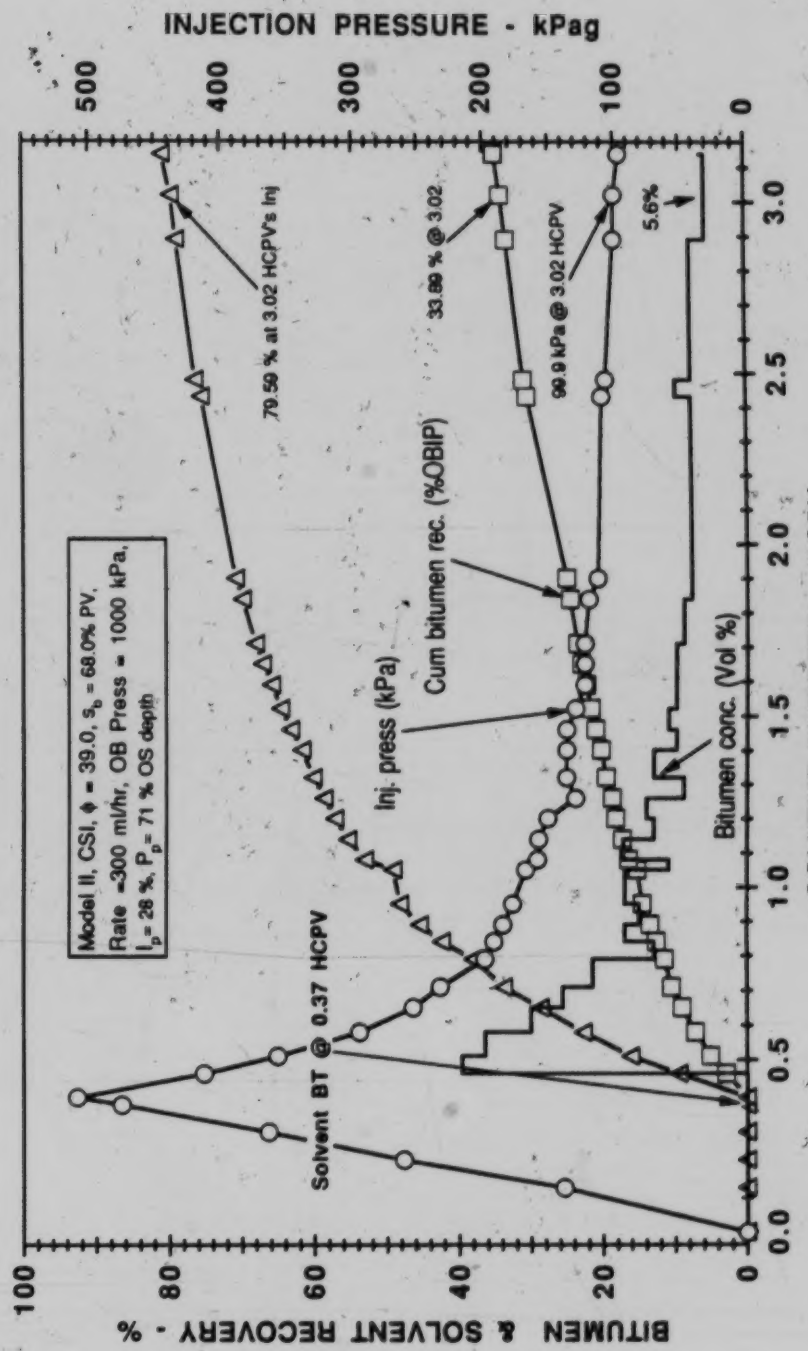


FIGURE C14: PRODUCTION HISTORY FOR RUN 14 - Homogeneous Pack Run.

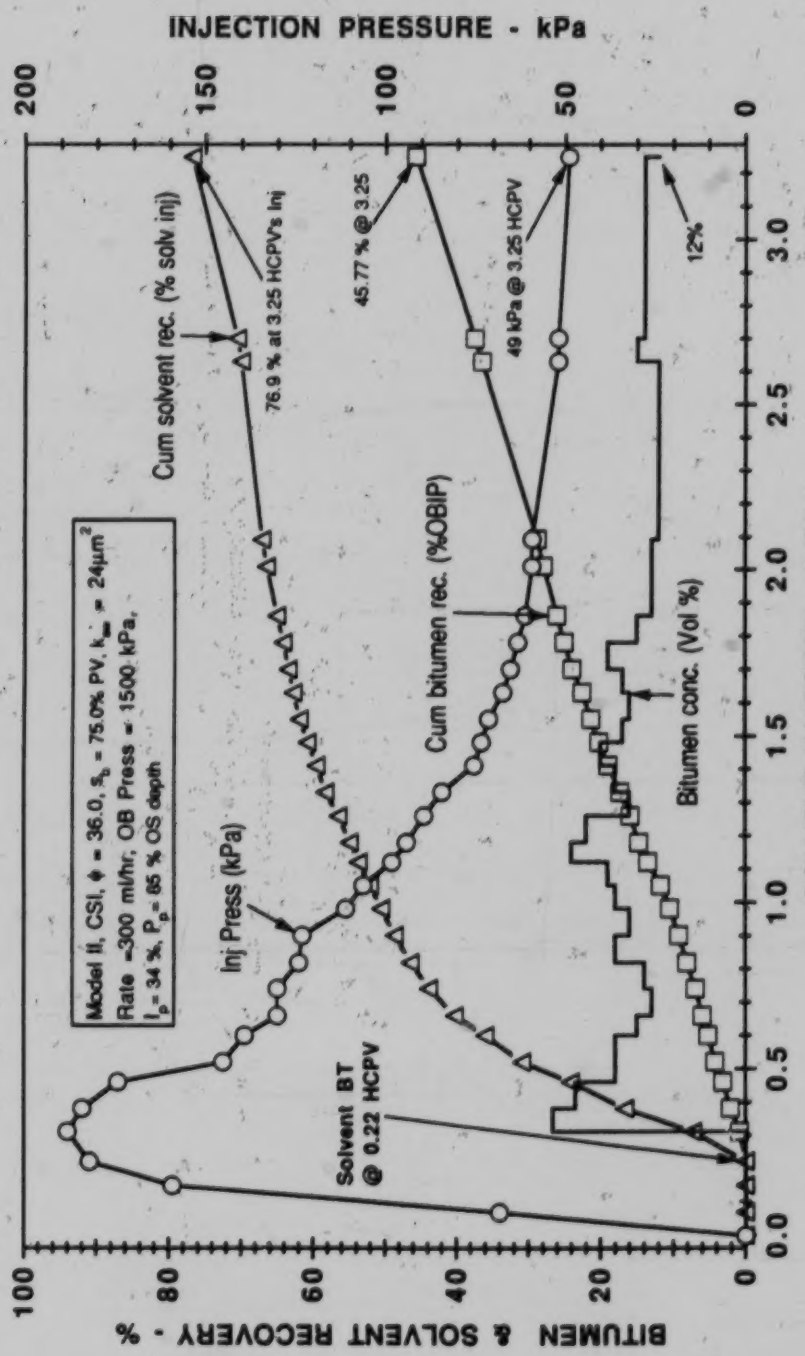


FIGURE C15: PRODUCTION HISTORY FOR RUN 15 - Bottom Water Run.

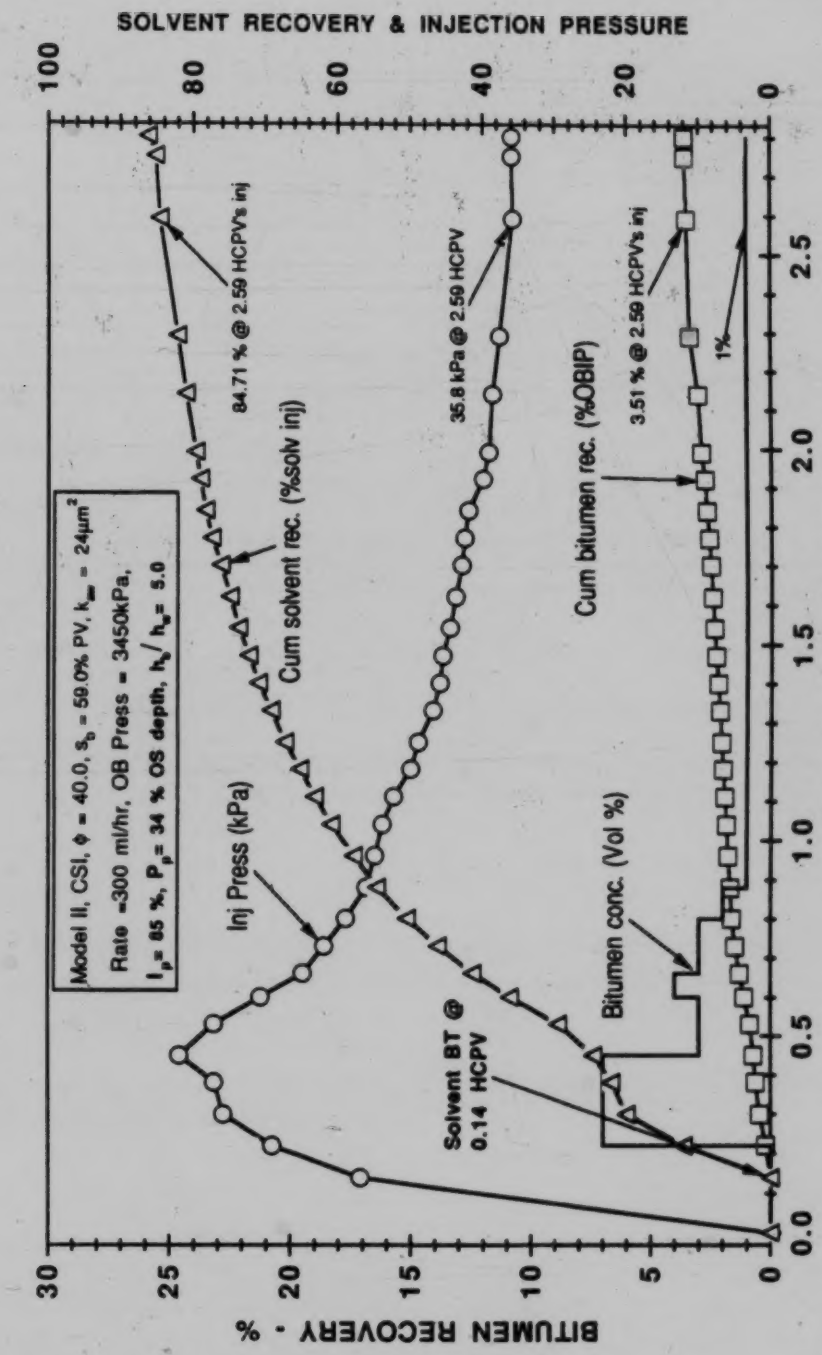


FIGURE C16: PRODUCTION HISTORY FOR RUN 16 - Effect of Well Penetration.

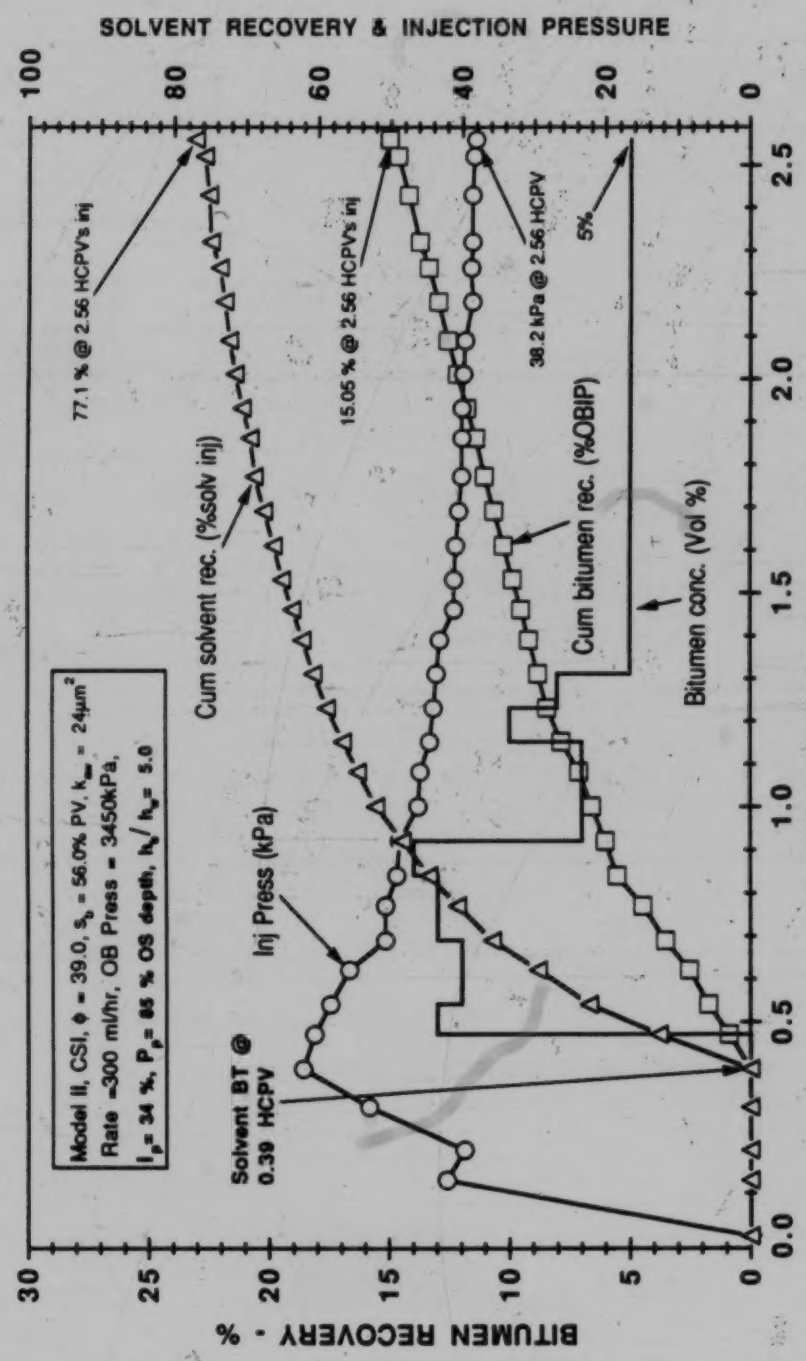

SOLVENT RECOVERY & INJECTION PRESSURE
BITUMEN RECOVERY - %
SOLVENT INJECTED - HCPV
Model II, CSI, ϕ = 39.0, S_b = 56.0% PV, k_av = 24μm²
Rate =300 ml/hr, OB Press = 3450kPa,
l_p= 34 %, P_p= 85 % OS depth, h_b/ h_w= 5.0
77.1 % @ 2.56 HCPVs inj
15.05 % @ 2.56 HCPVs inj
38.2 kPa @ 2.56 HCPV
5%
Cum solvent rec. (%solv inj)
Cum bitumen rec. (%OBIP)
Bitumen conc. (Vol %)
Inj Press (kPa)
Solvent BT @
0.39 HCPV

FIGURE C17: PRODUCTION HISTORY FOR RUN 17 - Effect of Well Penetration.

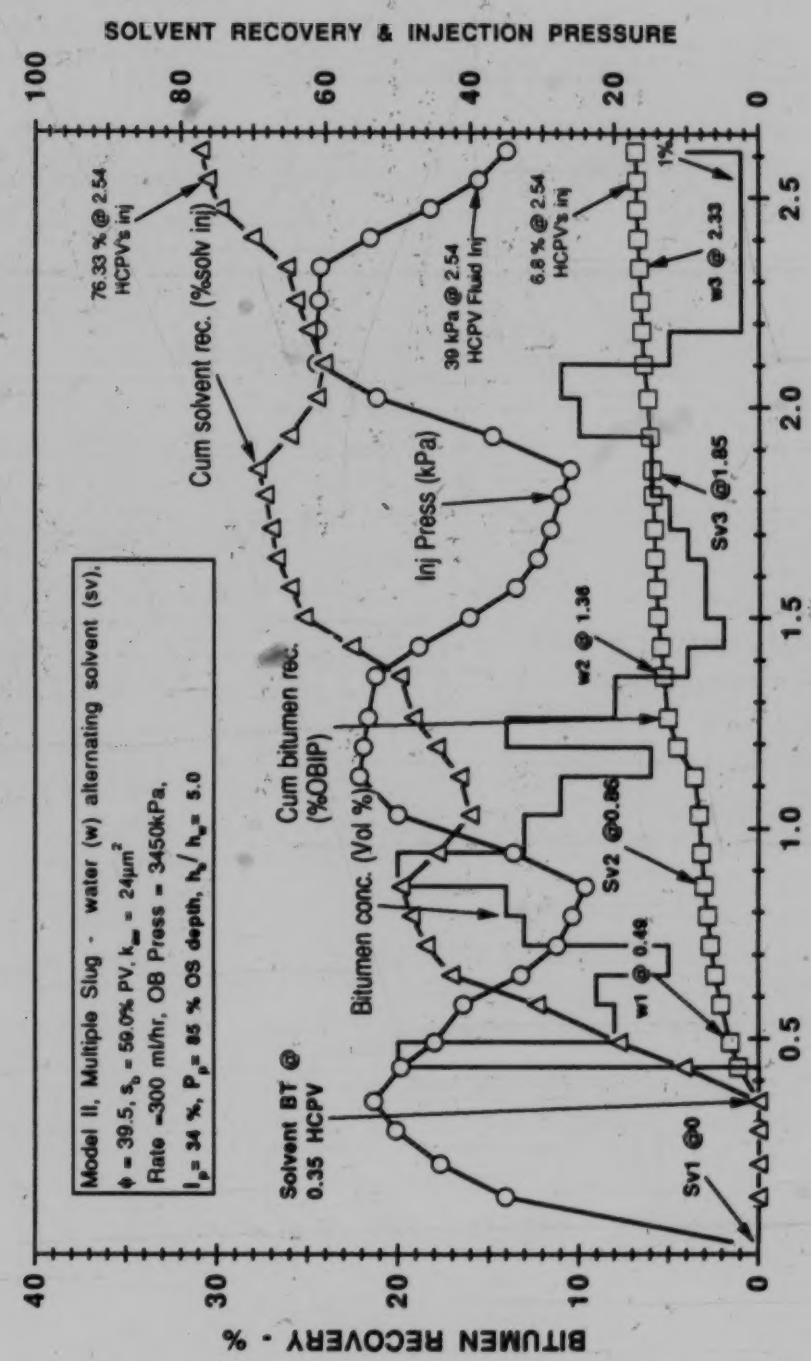

SOLVENT RECOVERY & INJECTION PRESSURE
BITUMEN RECOVERY - %
FLUID INJECTED - HCPV
Model II, Multiple Slug - water (w) alternating solvent (sv).
ϕ = 39.5, S_b = 59.0% PV, k_ab = 24μm²
Rate =300 ml/hr, OB Press = 3450kPa,
l_p= 34 %, P_p= 85 % OS depth, h_b/ h_w= 5.0
Solvent BT @ 0.35 HCPV
Bitumen conc. (Vol %)
Cum bitumen rec. (%OBIP)
Cum solvent rec. (%solv inj)
Inj Press (kPa)
76.33 % @ 2.54 HCPV's inj
30 kPa @ 2.54 HCPV Fluid Inj
6.8 % @ 2.54 HCPV's inj
Sv1 @0
w1 @ 0.48
Sv2 @0.86
w2 @ 1.38
Sv3 @1.85
w3 @ 2.33

FIGURE C18: PRODUCTION HISTORY FOR RUN 18 - Water Alternating Solvent Run.

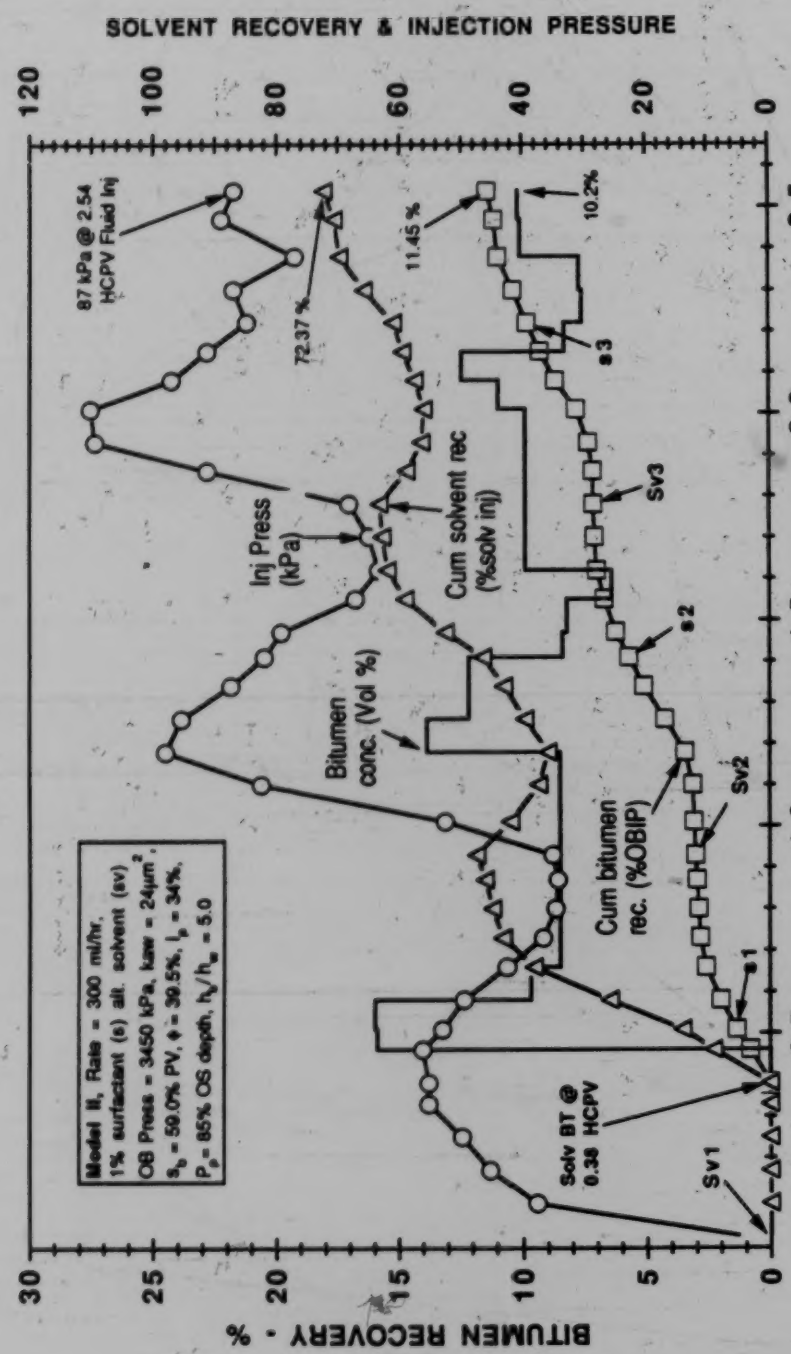


FIGURE C19: PRODUCTION HISTORY FOR RUN 19 - 1.0% Surfactant Alternating Solvent Run.

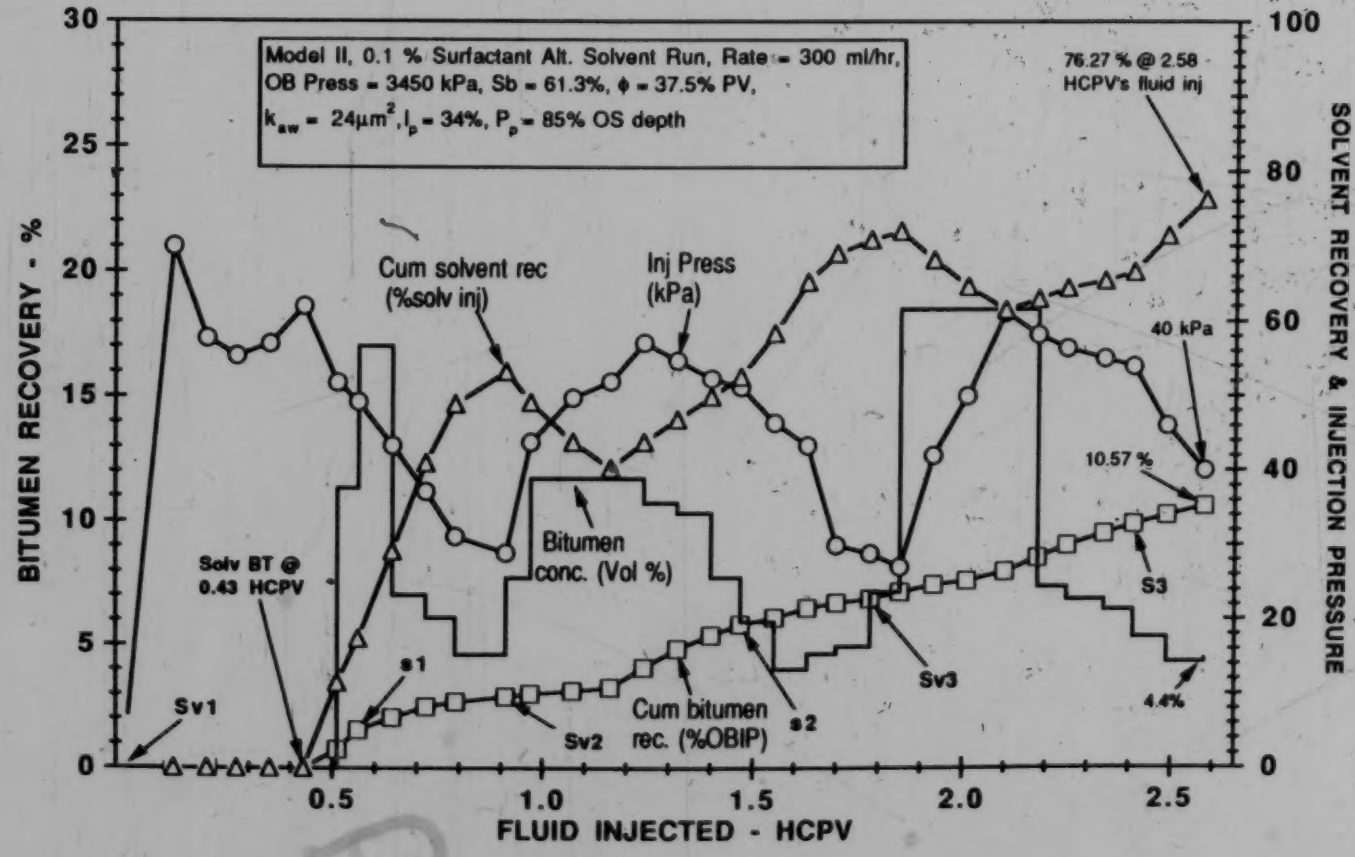


FIGURE C20: PRODUCTION HISTORY FOR RUN 20 - 0.1% Surfactant Alternating Solvent Run.

APPENDIX D
VOLUMETRIC BALANCE PLOTS

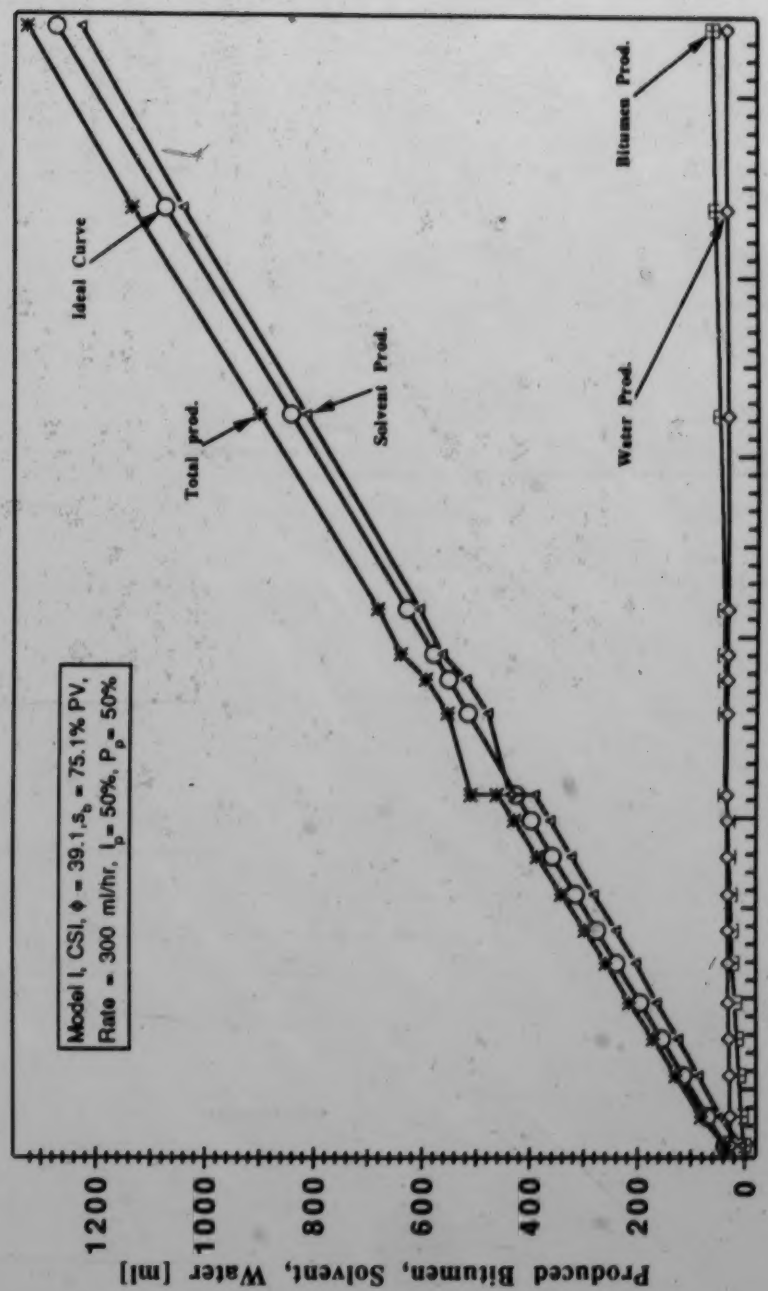


Figure D1: Volumetric Balance for Run 1 - Homogeneous Run.

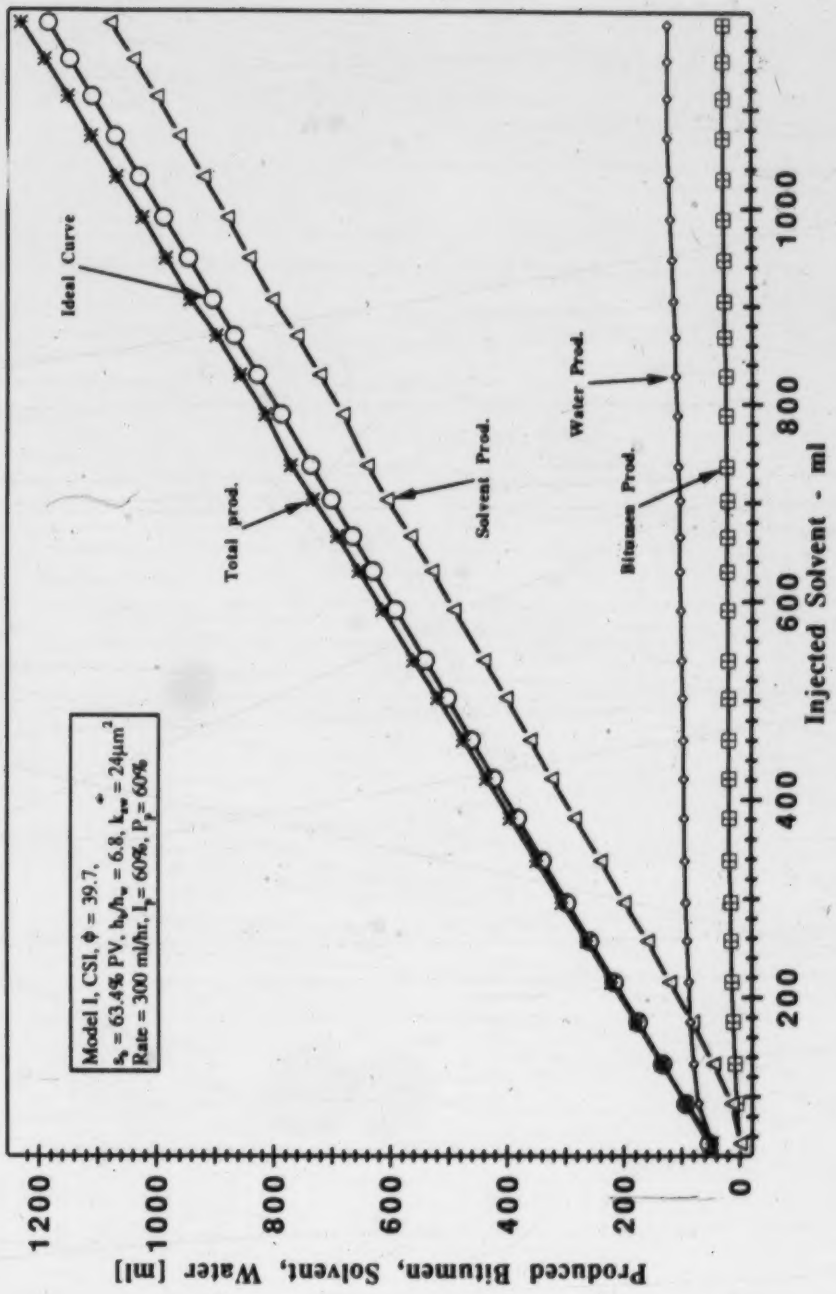


Figure D2: Volumetric Balance for Run 4 - Effect of Bottom Water Thickness.

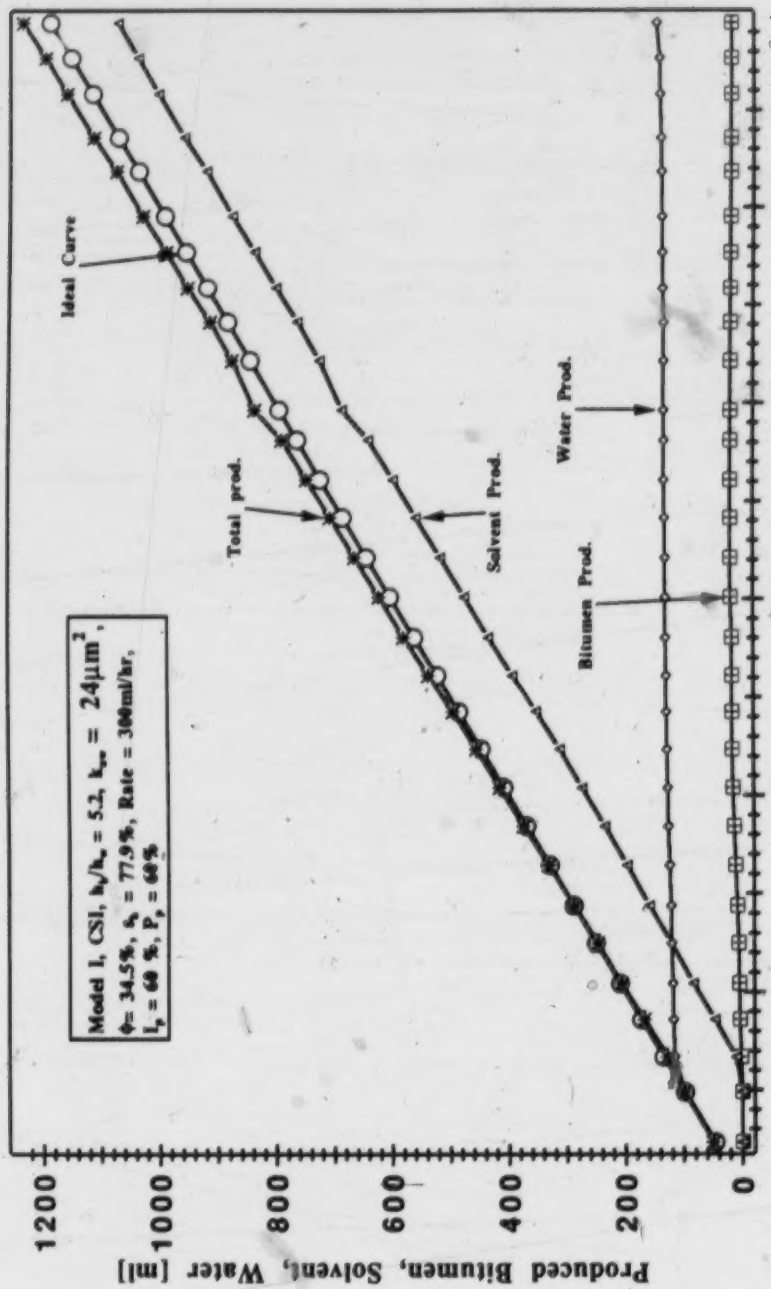


Figure D3: Volumetric Balance for Run 7 - Bottom Water Run.

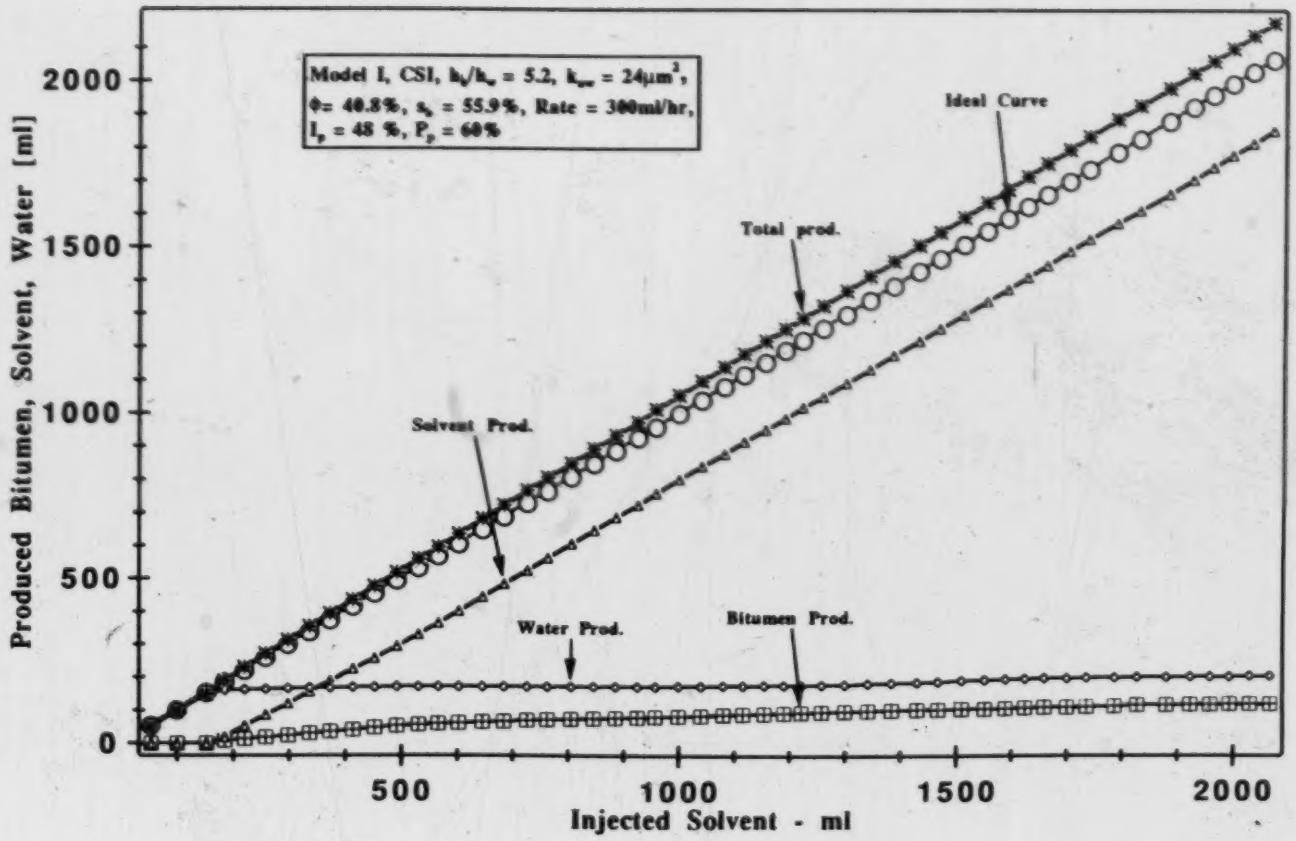


Figure D4: Volumetric Balance for Run 10 - Effect of Bottom Water Permeability.

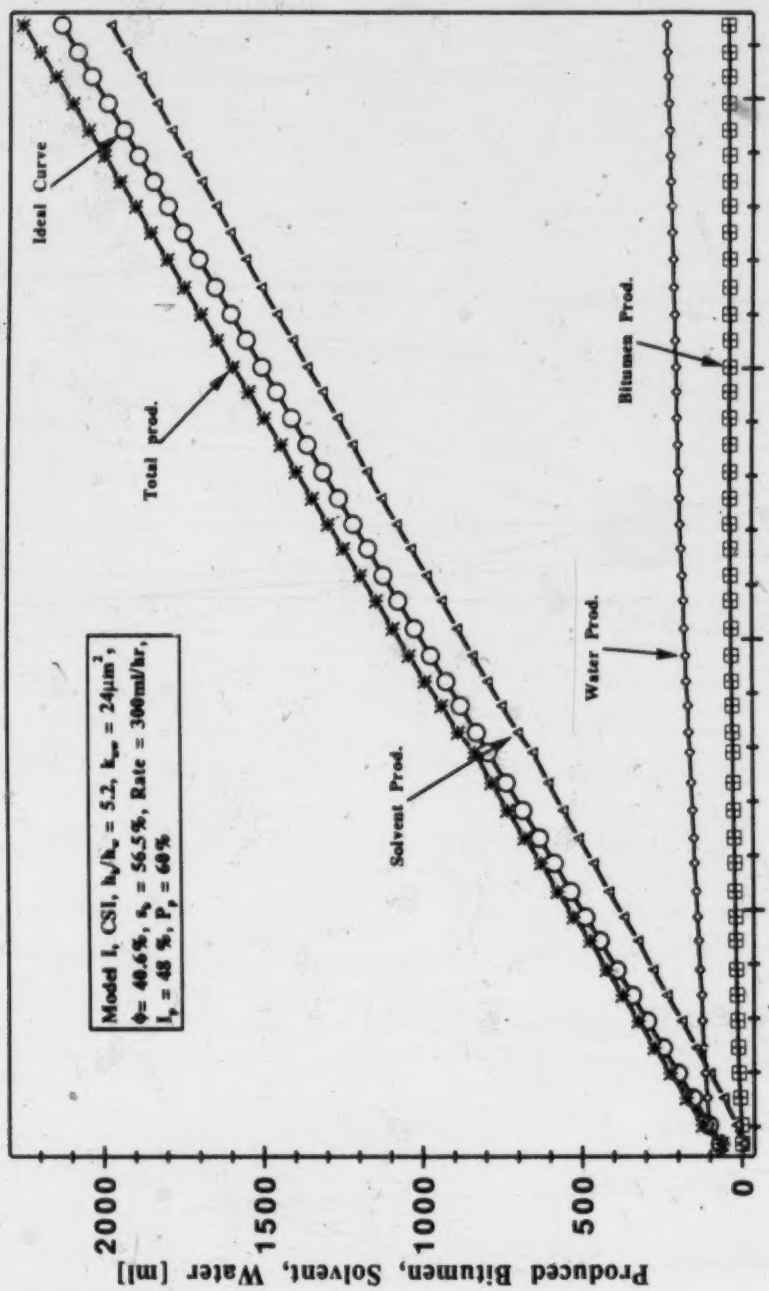


Figure D5: Volumetric Balance for Run 13.

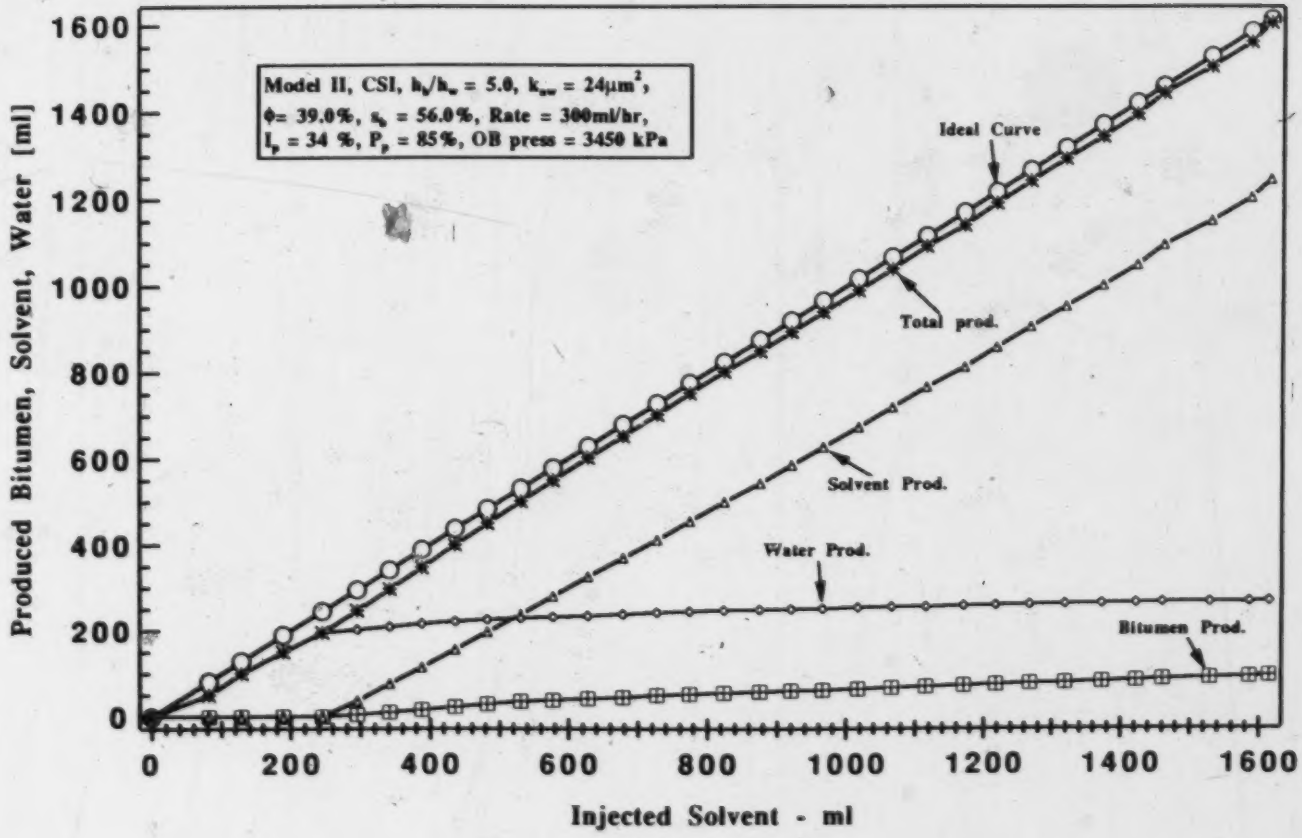


Figure D6: Volumetric Balance for Run 17.

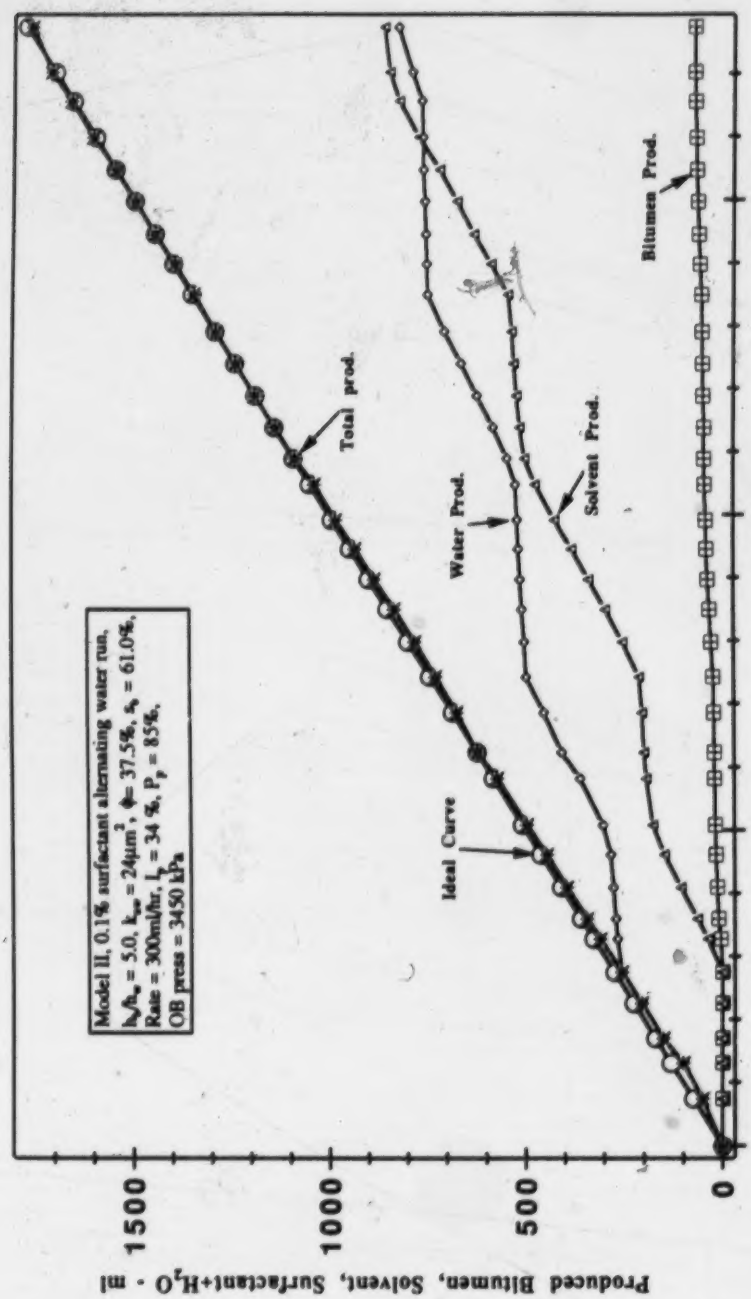


Figure D7: Volumetric Balance for Run 20.

APPENDIX E

COMPUTER LISTING, SAMPLE SIMULATION DATA AND OUTPUT SETS

This Appendix contains data sets for a homogeneous as well as a bottom water simulation run. An output for the produced bitumen concentration and recovery, solvent recovery and production rate as well as a partial output indicating the saturations, concentrations, etc. for the grids per time step.

```
      IMPLICIT REAL*8 (A-H,O-Z)
C
C&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&
&&&&&&&&&&
C
C     CREATED BY : MUSTAFA OGUZTORELI
C                  DEPT. OF MINERAL ENGINEERING
C                  UNIVERSITY OF ALBERTA
C
C     REVISED JANUARY 1990 BY MUSTAFA OGUZTORELI AND ANAR MURJI
C
C     PROGRAM 'LCHFIV' CALCULATES THE CONCENTRATION
C     AND SATURATION DISTRIBUTIONS FOR A TWO-DIMENSIONAL
C     LEACHING OF A SOLID OIL-PHASE IMMERSED IN A STREAMING
C     INCOMPRESSIBLE FLOW FIELD BOUNDED WITHIN A FINITE
C     POROUS REGION
C
C     THE SOLID PHASE CONSISTS OF SPHERICAL BITUMEN PELLETS
C     CONFINED TO THE PORES OF THE MEDIUM AND ARE
C     SUBJECT TO RADIAL DIFFUSION OF SOLVENT (DIFFUSING SPECIES)
C
C     THE LIQUID STREAM IS SUBJECT TO CONVECTIVE-DIFFUSION
C     WITH A SINK TERM TO ACCOUNT FOR SOLVENT ACCUMULATION
C     INTO THE SOLID PHASE
C
C     'LCHFIV' SOLVES A SYSTEM OF COUPLED EQUATIONS
C     (DIFFERENTIAL - INTEGRO-DIFFERENTIAL ) TO EQUATE
C     THE SOLVENT CONCENTRAION IN THE FREE STREAM AND
C     THE RELATIVE VOLUMES OF LIQUID AND SOLID PHASES
C
C     'LCHFIV' INCORPORATES OGUZTORELI'S T.C.P. METHOD
C     TO DISCRETIZE THE CONVECTIVE-DIFFUSION EQN.
C
C-------------------------------------------------------------
C
```

```
C     INPUT ON DEVICES 5 AND 1
C     PRINTOUT ON DEVICES 6 AND 2
C     OUTPUT FOR PLOTTING PROGRAM ON DEVICE 3
C
C     RUNNING SEQUENCE :
C
C     $R LCHFIV.OB 1=LCHDAT.00 2=LCHSIM.00 3=LCHPLT.00
C-------------------------------------------------------
C
C
C     DATA FILE STRUCTURE :
C
C NX,NY,              GRID DIMENSIONS
C                   NX : NUMBER OF X-INTERVALS
C                   NY : NUMBER OF Y-INTERVALS
C
C NI,NJ,NIO,NJO,          MATRIX INPUT/OUTPUT PARAMETERS
C                   NI : NUMBER OF ELEMENTS PER INPUT LINE
C                        (NI.LE.NX+1)
C                   NJ : NUMBER OF INTPUT LINES PER MATRIX
C                        (NJ.LE.NY+1)
C                   NIO : OUTPUT EVERY NIOTH X-ELEMENT
C                   NJO : OUTPUT EVERY NJOTH Y-ELEMENT
C
C LEN,WID,DZ,           PHYSICAL DIMENSIONS (cm)
C                   LEN : LENGTH
C                   WID : WIDTH
C                   DZ  : THICKNESS
C
C MUO,MUS,              FLUID VISCOSITIES (cp)
C                   MUO : OIL VISCOSITY
C                   MUS : SOLVENT VISCOSITY
C
C RHOO,RHOS,            FLUID DENSITIES (gm/cc)
C                   RHOO : OIL DENSITY
```

```
C                    RHOS : SOLVENT DENSITY
C
C HGT ?MATRIX (NX,NY)?          HEIGHT MATRIX (cm)
C                    ( NI ELEMENTS PER INPUT LINE )
C
C KX ?MATRIX (NX,NY)?       X- PERMEABILITY MATRIX (Darcy)
C                    ( NI ELEMENTS PER INPUT LINE )
C
C KY ?MATRIX (NX,NY)?       Y- PERMEABITILTY MATRIX (Darcy)
C                    ( NI ELEMENTS PER INPUT LINE )
C
C PHI ?MATRIX (NX,NY)?          POROSITY MATRIX
C                    ( NI ELEMENTS PER INPUT LINE )
C
C D0,FRF,SIGMA,DPAR,ALFAL,ALFAT,    DIFFUSION PARAMETERS
C                     D0   : MOLECULAR DIFFUSION COEF (cm**2/sec)
C                     FRF  : FORMATION RESISTIVITY FACTOR
C                     SIGMA : PACKING INHOMOGENEITY FACTOR
C                     DPAR  : PARTCLE DIAMATER (cm)
C                     ALFAL : LONGTITUDINAL PARAMETER (ALFAL=.5)
C                     ALFAT : TRANSVERSE PARAMETER (ALFAT=.0157)
C
C RST0,CST,DSOL,BETA0,          SPHERICAL PELLET PARAMETERS
C                     RST0  : INITIAL SPHERE RADIUS (cm)
C                     CST   : CRITICAL CONCENTRATION
C                     DSOL  : SOLID DIFFUSION COEF (cm**2/sec)
C                     BETA0 : MASS TRANSFER COEF (cm/sec)
C
C C0 ?MATRIX (NX,NY)?       INITIAL CONCENTRAION MATRIX
C                    ( NI ELEMENTS PER INPUT LINE )
C
C SAT ?MATRIX (NX,NY)?      INITIAL SATURATION MATRIX
C                    ( NI ELEMENTS PER INPUT LINE )
C
C NSPEC,                SPECIFIED NUMBER OF SOURCE/SINK 'S
```

```
C
C ISPEC ?MATRIX (NX,NY)?      SOURCE/SINK LOCATION MATRIX
C                  ( NI ELEMENTS PER INPUT LINE )
C                    ISPEC=0    : NO SOURCE/SINK
C                    ISPEC=1    : 1'ST SOURCE/SINK
C                    ISPEC=2    : 2'ND SOURCE/SINK
C                    ISPEC=NSPEC : LAST SOURCE/SINK
C
C INOUT ?MATRIX (NSPEC,1)?    SOURCE/SINK IDENTIFICATION MATRIX
C                  ( NI ELEMENTS PER INPUT LINE )
C                    INOUT=1  : SOURCE
C                    INOUT=-1 : SINK
C
C CSPEC ?MATRIX (NSPEC,1)?    CONCENTRATION SPECIFICATION MATRIX
C                  ( NI ELEMENTS PER INPUT LINE )
C                    SOURCE : SPECIFIES INJECTED CONCENTRATIONS
C                    SINK   : ARBITRARY (SET CSPEC==0.)
C
C PIN,POUT,                   PRESSURES (psi)
C                   PIN  : INLET (SOURCE) PRESSURE (INITIAL GUESS),
C                   POUT : OUTLET (SINK) PRESSURE
C
C ALFA,                DIFFUSIVE SOURCE RESISTIVITY FACTOR
C                   ALFA=0. : BOUNDARY IMPERMEABLE TO DIFFUSIVE FLUX
C                   ALFA=1. : NO RESISTANCE TO DIFFUSIVE FLUX
C
C MAXIT,IMAX,             MAXIT: MAXIMUM NUMBER OF ITERATIONS
C                   IMAX  : UPPER MAXIMUM INDEX FOR SUMMATION
C
C BIG,TINY,SMALL,TOL,STOL,    BIG  : COMPUTATIONALLY LARGE
NUMBER
C                   TINY  : COMPUTATIONALLY VERY SMALL NUMBER
C                   SMALL : COMPUTATIONALLY SMALL NUMBER
C                   TOL   : COMPUTATIONAL TOLERANCE
C                   STOL  : COMPUTATIONAL SUM TOLERANCE
```

```
C
C&&&
```

```
      DIMENSION DXX(500),DYY(500),DXXIJ(500),DYYIJ(500)
      DIMENSION U(500),THETA(500)
      DIMENSION CRSX(500),CRSY(500)
      DIMENSION XNC(500),YNC(500)
      DIMENSION RST(20000),CONV(500),IFLG1(500),IFLG2(500)
      DIMENSION NSPH(500),BETA(500),ADS(500)
      DIMENSION F1(500),FN(500),FNP1(500)
      DIMENSION COS2(500),SIN2(500),COSIN(500)
      DIMENSION W1(500),W2(500)
      DIMENSION CM(500),M(50)
      DIMENSION CNHLF(500),RSTHLF(500),SAT(500)
      DIMENSION TAU(500)
C
      DATA GRAV,COEFF /9.81D0,14.7D0/
C
      PI=2.D0*DARSIN(1.D0)
C
C---------- FORMAT ----------
C
 1    FORMAT('1')
 2    FORMAT(4I5)
 3    FORMAT(6G19.6)
 4    FORMAT(21G16.6)
 5    FORMAT(/'LENGTH (cm) =',G15.4,/
     1       ,'WIDTH  (cm) =',G15.4,/
     2       ,'THICK. (cm) =',G15.4)
 6    FORMAT(/,'OIL VISCOSITY (cp) =',G15.4,/
     1       ,'SOL VISCOSITY (cp) =',G15.4)
 7    FORMAT(/,'OIL DENSITY  (gm/cc) =',G15.4,/
     1       ,'SOL DENSITY  (gm/cc) =',G15.4)
 8    FORMAT(/,'MOLECULAR DIFF COEF (cm**2/sec) =',G15.4,
     1       /,'FORMATION RESISTIVITY FACTOR   =',G15.4,
     2       /,'PARTICLE DIA (GRAIN SIZE)  (cm) =',G15.4,
     3       /,'PACKING INHOMOGENEITY FACTOR   =',G15.4)
 9    FORMAT(/,'INITIAL BITUMEN RADIUS (cm) =',G15.4,
```

```
     1      /,'CONSTANT SURFACE CONC.      =',G15.4,
     2      /,'SOLID DIFF COEF (cm**2/sec) =',G15.4,
     3      /,'MASS TRANSFER COEF (cm/sec) =',G15.4)
    10   FORMAT('1',48X,'PERMEABILITY (KX Darcy)'/
     1          ,48X,'----------------------'/)
    11   FORMAT(//,48X,'PERMEABILITY (KY Darcy)'/
     1          ,48X,'----------------------'/)
    12    FORMAT('1',54X,'HEIGHT (cm)'/,54X,'---------'/)
    13    FORMAT(//,52X,'POROSITY'/,52X,'--------'/)
    14   FORMAT(I1)
    15   FORMAT(2G16.6)
    16   FORMAT(G16.6,I3)
    17   FORMAT(//,'ENTER : FLOW RATE - QIN (cc/sec)'/,'?')
    18   FORMAT(/,'ENTER : PORE VOL. INJECTED (dPV,NdPV)'/,'?')
    19   FORMAT(//,53X,'CONCENTRATION'/,
     1          53X,'-------------'/)
    20   FORMAT(//,53X,'SATURATION'/,
     1          53X,'----------'/)
    21   FORMAT(52X,'*      T.C.P.      *')
    22   FORMAT(/,'P.V. SOL INJECTED  =',G16.6,
     1 /,'P.V. BIT PRODUCED  =',G16.6)
    23   FORMAT('TIME (days)       =',G16.6)
    24   FORMAT(/,'FLOW RATE (cc/sec) =' ,2G16.4)
    25   FORMAT(/,'INLET PRES. (psi)  =',G16.6)
    26   FORMAT('OUTLET PRES.(psi)  =',G16.6)
    27    FORMAT(/,'X-CELL NO. (MAX,MIN) = (',G9.3,',',G9.3,')'/,
     1 'Y-CELL NO. (MAX,MIN) = (',G9.3,',',G9.3,')')
    28   FORMAT(/,'DIFF. MASS BAL. =',G16.6)
    29   FORMAT('CUM. MASS BAL.  =',G16.6)
    30   FORMAT(/,'ITERATIONS   K  =',I3,/)
    31   FORMAT(//,50X,'PRESSURE (psi)'/,
     1          50X,'--------------'/)
    32   FORMAT(//,52X,' UX (cm/sec) '/,
     1          52X,'------------'/)
    33   FORMAT(//,52X,' UY (cm/sec) '/,
```

```
     1        52X,'----------'/)
  34  FORMAT(//,50X,'DXX (cm**2/sec)'/,
     1        50X,'--------------'/)
  35  FORMAT(//,50X,'DYY (cm**2/sec)'/,
     1        50X,'--------------'/)
  36  FORMAT(//,53X,'CELL.NO.-X'/,
     1        53X,'----------'/)
  37  FORMAT(//,53X,'CELL.NO.-Y'/,
     1        53X,'----------'/)
  38  FORMAT(//,53X,'SPHERE RADIUS'/,
     1        53X,'------------'/)
  39  FORMAT(//,'OUTPUT  ? (0,1)'/,'?')
  40  FORMAT(5G9.3)
  41  FORMAT('9999.')
C
C-------------------------------------------------------------
C
C       INITIALIZE
C
C-------------------------------------------------------------
C
      N=0
C
      TAU(1)=0.D0
      DT=0.D0
C
C
      QSOCM=0.D0
      QSICM=0.D0
      DFSICM=0.D0
      QINCM=0.D0
      ADSCM=0.D0
C
      PVINJ=0.D0
      SOLREC=0.D0
```

```
      BITREC=0.D0
C
C-----------------------------------------------------------
C
C       INPUT GRID PARAMETERS
C
C-----------------------------------------------------------
C
      READ(1,2)NXM1,NYM1
C
      NX=NXM1+1
      NY=NYM1+1
      NA=NX*NY
      NAMNX=NA-NX
C
      IF(MOD(NA,2).EQ.0) GO TO 100
C
      NA2=(NA-1)/2
      NA2P1=NA2+1
C
      GO TO 110
C
  100 NA2=NA/2
      NA2P1=NA2
C
  110 READ(1,3)LEN,WID,DZ
C
      DX=LEN/NXM1
      DY=WID/NYM1
C
      DO 120 I=1,NX
      DO 120 J=1,NY
C
      IJ=I+NX*(J-1)
C
```

```
      MOD1(IJ)=MOD(IJ,NX)
C
      IJXM(IJ)=IJ+(J-1)
      IJXP(IJ)=IJ+J
      IJYM(IJ)=IJ
      IJYP(IJ)=IJ+NX
C
      DXI=0.D0
      DXIM1=0.D0
      DYJ=0.D0
      DYJM1=0.D0
C
      IF(I.NE.NX) DXI=DX
      IF(I.NE.1) DXIM1=DX
      IF(J.NE.NY) DYJ=DY
      IF(J.NE.1) DYJM1=DY
C
      AX(IJ)=.5D0*(DYJ+DYJM1)*DZ
      AY(IJ)=.5D0*(DXI+DXIM1)*DZ
C
      VB(IJ)=.25D0*(DXI+DXIM1)*(DYJ+DYJM1)*DZ
C
  120 CONTINUE
C
C-------------------------------------------------------
C
C       INPUT I/O PARAMTERS
C
C-------------------------------------------------------
C
      READ(1,2)NI,NJ,NIO,NJO
C
      MI=NX/NI
      MJ=NY/NJ
      IF(MOD(NX,NI).GT.0) MI=MI+1
```

```
      IF(MOD(NY,NJ).GT.0) MJ=MJ+1
C
C-------------------------------------------------------
C
C       INPUT FLUID PARAMETERS
C
C-------------------------------------------------------
C
      READ(1,3)MUO,MUS,ALFAMU
      READ(1,3)RHOO,RHOS
C
      LNMUO=DLOG(1.D-2*MUO)
      LNMUS=DLOG(1.D-2*MUS)
      ALFA1=RHOO/RHOS
      BETA1=-DLOG(5.D-4)
      AC=(1.D0-ALFA1)*LNMUO*LNMUS+BETA1*(LNMUS-ALFA1*LNMUO)
      BC=ALFA1*LNMUO*(LNMUS+BETA1)
      DC=LNMUO-ALFA1*LNMUS+BETA1*(1.D0-ALFA1)
      EC=ALFA1*(LNMUS+BETA1)
C
C-------------------------------------------------------
C
C       INPUT POROUS MEDIUM PARAMETERS
C
C-------------------------------------------------------
C
      CALL INPUT1 (1,NX,NY,HGT)
C
      CALL INPUT1 (1,NX,NY,KX0)
      CALL INPUT1 (1,NX,NY,KY0)
C
      CALL INPUT1 (1,NX,NY,PHIMTX)
C
C-------------------------------------------------------
C
```

```
C       INPUT DIFFUSIVITY PARAMTERS
C
C-----------------------------------------------------
C
      READ(1,3)D0,FRF,SIGMA,DPAR,ALFAL,ALFAT
C
C-----------------------------------------------------
C
C       INPUT SPHERICAL SOLID PELLET PARAMETERS
C
C-----------------------------------------------------
C
      READ(1,3)RST0,CST,DSOL,BETA0
C
C-----------------------------------------------------
C
C       INITIALIZE CONCENTRATION AND FLUID SATURATION
C
C-----------------------------------------------------
C
      CALL INPUT1 (1,NX,NY,CN)
      CALL INPUT1 (1,NX,NY,SAT)
C
C-----------------------------------------------------
C
C     CALCULATE SPHERE NUMBER DENSITY DISTRIBUTION
C
C-----------------------------------------------------
C
      DO 130 IJ=1,NA
C
 130   NSPH(IJ)=3.D0*(1.D0-SAT(IJ))*PHIMTX(IJ)/(RST0**3)
C
C-----------------------------------------------------
C
```

```
C       INPUT SPECIFIED BOUNDARY VALUES
C
C-----------------------------------------------------------
C
      READ(1,2)NSPEC
C
      CALL INPUT2 (1,NX,NY,ISPEC)
      CALL INPUT2 (1,NSPEC,1,INOUT)
      CALL INPUT1 (1,NSPEC,1,CSPEC)
C
      READ(1,3) PIN,POUT
C
      READ(1,3) ALFA
      IF(ALFA.EQ.1.D0) ALFA=(1.D0-SMALL)
      IF(ALFA.EQ.0.D0) ALFA=SMALL
C
C-----------------------------------------------------------
C
C       INPUT COMPUTATIONAL PARAMETERS
C
C-----------------------------------------------------------
C
      READ(1,2) MAXIT,IMAX
      READ(1,3)BIG,TINY,SMALL,TOL,STOL
C
C-----------------------------------------------------------
C
C       ESTABLISH D4 ORDERING
C
C-----------------------------------------------------------
C
      WRITE(3,2) NX,NY
C
      CALL D4MAP(NX,NY,1)
C
```

```
C-----------------------------------------------------------
C
C       OUTPUT
C
C-----------------------------------------------------------
C
      WRITE(2,5) LEN,WID,DZ
      WRITE(2,6) MUO,MUS
      WRITE(2,7) RHOO,RHOS
      WRITE(2,8) D0,FRF,DPAR,SIGMA
      WRITE(2,9) RST0,CST,DSOL,BETA0
C
      WRITE(2,10)
      CALL OUTPT2 (1,2,KX0)
C
      WRITE(2,11)
      CALL OUTPT2 (1,2,KY0)
C
      WRITE(2,12)
      CALL OUTPT2 (1,2,HGT)
C
      WRITE(2,13)
      CALL OUTPT2 (1,2,PHIMTX)
C
C-----------------------------------------------------------
C
      WRITE(6,1)
      WRITE(2,1)
C
      S0=0.D0
      PV=0.D0
      BIT=0.D0
C
      DO 150 IJ=1,NA
C
```

```
      PV=PV+PHIMTX(IJ)*VB(IJ)
      BIT=BIT+(1.D0-SAT(IJ))*PHIMTX(IJ)*VB(IJ)
C
C
      IF(ISPEC(IJ).EQ.0) GO TO 150
      IF(INOUT(ISPEC(IJ)).NE.1) GO TO 140
C
      PSPEC(ISPEC(IJ))=PIN
      CN(IJ)=.5D0*(CN(IJ)+CSPEC(ISPEC(IJ)))
C
      GO TO 150
C
  140 PSPEC(ISPEC(IJ))=POUT
C
  150 S0=S0+SAT(IJ)*PHIMTX(IJ)*VB(IJ)*CN(IJ)
C
      WRITE(6,19)
      WRITE(2,19)
C
      CALL OUTPT2 (2,2,CN)
      CALL OUTPT2 (2,6,CN)
C
      WRITE(6,20)
      WRITE(2,20)
C
      CALL OUTPT2 (2,2,SAT)
      CALL OUTPT2 (2,6,SAT)
C
      DO 160 IJ=1,NA
C
      RST(IJ)=RST0
      PN(IJ)=0.0
      FN(IJ)=0.D0
      CONV(IJ)=0.D0
      IFLG1(IJ)=0
```

```
      IFLG2(IJ)=0
      BETA(IJ)=BETA0
C
 160  CONTINUE
C
C******************** MAIN LOOP *************************
C
C-----------------------------------------------------------
C
C       INPUT INJECTED SOLVENT VOLUME
C
C       QIN  : CONSTANT FLOW RATE TO BE MAINTAINED OVER TIME STEP
C       DPV  : FRACTIONAL PORE VOLUME INJECTED PER TIME STEP
C       NDT  : NUMBER OF TIME STEPS
C
C-----------------------------------------------------------
C
 1000 WRITE(6,17)
      WRITE(2,17)
C
      READ(5,16) QIN
C
      WRITE(6,18)
      WRITE(2,18)
C
      READ(5,16) DPV,NDPV
C
      IF(DPV.EQ.0.D0) GO TO 9999
C
      QINSUM=0.D0
C
      DO 170 IJ=1,NA
C
      IF(ISPEC(IJ).EQ.0) GO TO 170
      IF(INOUT(ISPEC(IJ)).NE.1) GO TO 170
```

```
C
      QINSUM=QINSUM+QIN
C
 170  CONTINUE
C
      DO 5000 IDPV=1,NDPV
C
      N=N+1
C
      NP1=N+1
      NM1=N-1
C
C-------------------------------------------------------
C
C       USING  T.C.P. (OGUZTORELI) METHOD TO SOLVE
C       CONVECTIVE-DIFFUSSION EQUATION
C
C-------------------------------------------------------
C
      SN=0.D0
C
      DO 1001 IJ=1,NA
C
      IJN=IJ+NA*(N-1)
C
      RHON(IJ)=RHOO+(RHOS-RHOO)*CN(IJ)
      PHIN(IJ)=PHIMTX(IJ)-NSPH(IJ)*RST(IJN)**3/3.D0
      MU(IJ)=1.D2*DEXP((AC*CN(IJ)+BC)/(DC*CN(IJ)+EC))
C
      SN=SN+SAT(IJ)*PHIMTX(IJ)*VB(IJ)*CN(IJ)
1001  CONTINUE
C
C
C-------------------------------------------------------
C
```

```
C       PRESSURE-CONCENTRAION DISTRIBUTIONS
C
C-------------------------------------------------------
C
      K=0
C
      DO 1010 IJ=1,NA
C
      IJN=IJ+NA*(N-1)
      IJNP1=IJ+NA*N
C
      CNP1(IJ)=CN(IJ)
      RHONP1(IJ)=RHON(IJ)
      PHINP1(IJ)=PHIN(IJ)
 1010 RST(IJNP1)=RST(IJN)
C
 2000 DO 2001 IJ=1,NA
C
      IJN=IJ+NA*(N-1)
      IJNP1=IJ+NA*N
C
      CNHLF(IJ)=.5D0*(CNP1(IJ)+CN(IJ))
      RHO(IJ)=RHOO+(RHOS-RHOO)*CNHLF(IJ)
      RHONP1(IJ)=RHOO+(RHOS-RHOO)*CNP1(IJ)
      RSTHLF(IJ)=.5D0*(RST(IJN)+RST(IJNP1))
      PHI(IJ)=PHIMTX(IJ)-NSPH(IJ)*RSTHLF(IJ)**3/3.D0
      PHINP1(IJ)=PHIMTX(IJ)-NSPH(IJ)*RST(IJNP1)**3/3.D0
C
 2001 CM(IJ)=CNP1(IJ)
C
      DT=PV*DPV/QINSUM
C
      TAU(NP1)=TAU(N)+DT
      TIME=TAU(NP1)/(3600.D0*24.D0)
C
```

```
C-----------------------------------------------------------
C
C     CHECK FOR ZERO SPHERE RADIUS AND STOP DISSOLUTION
C
C-----------------------------------------------------------
C
C
      DO 2100 IJ=1,NA
C
      IJN=IJ+NA*(N-1)
C
      IF(RSTHLF(IJ).LE.TOL) IFLG1(IJ)=1
      IF(RST(IJN).LE.TINY)  IFLG2(IJ)=1
C
      IF(IFLG2(IJ).EQ.1) BETA(IJ)=0.D0
C
 2100 CONTINUE
C
C-----------------------------------------------------------
C
C     CALCULATE FUNCTION FOR INTEGRO-DIFFERENTIAL EQUATION
C
C-----------------------------------------------------------
C
      DT1=.5D0*(TAU(NP1)-TAU(N))
C
      ILO=1
C
 2102 IF(TAU(ILO+1).GT.DT1) GO TO 2105
C
      ILO=ILO+1
C
      GO TO 2102
C
 2105 DO 2120 IJ=1,NA
```

```
C
      IF(IFLG1(IJ).NE.0) GO TO 2120
C
      IJNP1=IJ+NA*N
C
      I=0
      SUM=0.D0
C
      RSTSQ=RST(IJNP1)*RST(IJNP1)
      AEXP=PI*PI*DSOL/RSTSQ
C
 2110 I=I+1
C
      SUM1=SUM
      SUM=SUM+(DEXP(-I*I*AEXP*TAU(NP1)))/(I*I)
C
      TOL1=STOL*DABS(SUM)
      DSUM=DABS(SUM-SUM1)
C
      IF(DSUM.GT.TOL1.AND.I.LT.IMAX) GO TO 2110
C
      FNP1(IJ)=4.D0*PI*CST*RSTSQ*(1.D0/3.D0-2.D0*SUM/(PI*PI))
C
      I=0
      SUM=0.D0
C
      IJLO=IJ+NA*(ILO-1)
      IJLOP1=IJ+NA*ILO
C
      R1HLF=RST(IJLO)+
     1 (DT1-TAU(ILO))*(RST(IJLOP1)-RST(IJLO))/
     2 (TAU(ILO+1)-TAU(ILO))
C
      RSTSQ=R1HLF*R1HLF
      AEXP=PI*PI*DSOL/RSTSQ
```

```
C
 2115  I=I+1
C
      SUM1=SUM
      SUM=SUM+(DEXP(-I*I*AEXP*DT1))/(I*I)
C
      TOL1=STOL*DABS(SUM)
      DSUM=DABS(SUM-SUM1)
C
      IF(DSUM.GT.TOL1.AND.I.LT.IMAX) GO TO 2115
C
      F1(IJ)=4.D0*PI*CST*RSTSQ*(1.D0/3.D0-2.D0*SUM/(PI*PI))
C
 2120  CONTINUE
C
C-------------------------------------------------------
C
C     EVALUATE CONVOLUTION INTEGRAL
C     (USING LINEAR INTERPOLALTION)
C
C-------------------------------------------------------
C
C
      IF(N.EQ.1) GO TO 2200
C
      DO 2190 IJ=1,NA
C
      CONV(IJ)=0.D0
C
      IF(IFLG1(IJ).NE.0) GO TO 2190
C
      DO 2191 J=1,NM1
C
      JP1=J+1
C
```

```
      TNJ=TAU(N)-.5D0*(TAU(J)+TAU(JP1))
C
      ILO=1
      IHI=NP1
C
 2150 MID=(ILO+IHI)/2
C
      DTAU=TAU(MID)-TNJ
C
      IF(DTAU.LE.0) GO TO 2155
      IF(DTAU.GT.0) GO TO 2160
C
 2155 ILO=MID
C
      GO TO 2165
C
 2160 IHI=MID
C
 2165 IF((IHI-ILO).GT.1) GO TO 2150
C
      IJLO=IJ+NA*(ILO-1)
      IJLOP1=IJ+NA*ILO
C
      RNJ=RST(IJLO)+
     1 (TNJ-TAU(ILO))*(RST(IJLOP1)-RST(IJLO))/
     2 (TAU(ILO+1)-TAU(ILO))
C
      I=0
      SUM=0.D0
C
      RSTSQ=RNJ*RNJ
      AEXP=PI*PI*DSOL/RSTSQ
C
 2167 I=I+1
C
```

```
      SUM1=SUM
      SUM=SUM+(DEXP(-I*I*AEXP*TNJ))/(I*I)
C
      TOL1=STOL*DABS(SUM)
      DSUM=DABS(SUM-SUM1)
C
      IF(DSUM.GT.TOL1.AND.I.LT.IMAX) GO TO 2167
C
      FNJ=4.D0*PI*CST*RSTSQ*(1.D0/3.D0-2.D0*SUM/(PI*PI))
C
      TNP1J=TAU(NP1)-.5D0*(TAU(J)+TAU(JP1))
C
      ILO=1
      IHI=NP1
C
 2170 MID=(ILO+IHI)/2
C
      DTAU=TAU(MID)-TNP1J
C
      IF(DTAU.LE.0) GO TO 2175
      IF(DTAU.GT.0) GO TO 2180
C
 2175 ILO=MID
C
      GO TO 2185
C
 2180 IHI=MID
C
 2185 IF((IHI-ILO).GT.1) GO TO 2170
C
      IJLO=IJ+NA*(ILO-1)
      IJLOP1=IJ+NA*ILO
C
      RNP1J=RST(IJLO)+
     1 (TNP1J-TAU(ILO))*(RST(IJLOP1)-RST(IJLO))/
```

```
     2 (TAU(ILO+1)-TAU(ILO))
C
      I=0
      SUM=0.D0
C
      RSTSQ=RNP1J*RNP1J
      AEXP=PI*PI*DSOL/RSTSQ
C
 2187 I=I+1
C
      SUM1=SUM
      SUM=SUM+(DEXP(-I*I*AEXP*TNP1J))/(I*I)
C
      TOL1=STOL*DABS(SUM)
      DSUM=DABS(SUM-SUM1)
C
      IF(DSUM.GT.TOL1.AND.I.LT.IMAX) GO TO 2187
C
      FNP1J=4.D0*PI*CST*RSTSQ*(1.D0/3.D0-2.D0*SUM/(PI*PI))
C
      IJJ=IJ+NA*(J-1)
      IJJP1=IJ+NA*J
C
      CONV(IJ)=CONV(IJ)+(RST(IJJP1)-RST(IJJ))*(FNP1J-FNJ)
C
 2191 CONTINUE
 2190 CONTINUE
C
C-------------------------------------------------------
C
C     SOLVE THE SYSTEM OF DECOUPLED EQUATIONS
C
C-------------------------------------------------------
C
 2200 DO 2250 IJ=1,NA
```

```
C
      IJN=IJ+NA*(N-1)
      IJNP1=IJ+NA*N
C
      RST(IJNP1)=TINY
C
      IF(IFLG1(IJ).NE.0) GO TO 2250
C
      RSTSQ=4.D0*PI*RSTHLF(IJ)*RSTHLF(IJ)
C
      A=CNHLF(IJ)*RSTSQ-F1(IJ)
      X=RST(IJ)*(FNP1(IJ)-FN(IJ))+CONV(IJ)
     1 +RST(IJN)*(CNHLF(IJ)*RSTSQ-F1(IJ))
     2 -RSTSQ*BETA(IJ)*(CNHLF(IJ)-CST)*DT
C
      RST(IJNP1)=X/A
C
      DSAT=RST(IJNP1)**3*NSPH(IJ)/(3.D0*PHIMTX(IJ))
      IF(DSAT.GT.1.D0.OR.RST(IJNP1).LE.0.D0) RST(IJNP1)=TINY
 2250 CONTINUE
C
C-------------------------------------------------------
C
C       SOLVE DARCY-CONTINUITY EQUATION
C
C-------------------------------------------------------
C
 3001  DO 3000 IJ=1,NA
C
      KPHI=(1.D0-PHIMTX(IJ))**2*PHI(IJ)**3
     1 /(PHIMTX(IJ)**3*(1.D0-PHI(IJ))**2)
C
      KX(IJ)=KPHI*KX0(IJ)
 3000 KY(IJ)=KPHI*KY0(IJ)
C
```

```
      DO 3020 IJ=1,NA
C
      IP1J=IJ+1
      IJP1=IJ+NX
C
      IF(MOD1(IJ).EQ.0) GO TO 3010
C
      IDWN=IP1J
      IF(PN(IJ).GT.PN(IP1J)) IDWN=IJ
C
      TX(IJXP(IJ))=KX(IDWN)/(DX*COEFF*MU(IDWN))
      TXRHO(IJXP(IJ))=RHON(IDWN)
C
 3010 IF(IJ.GT.NAMNX) GO TO 3020
C
      JDWN=IJP1
      IF(PN(IJ).GT.PN(IJP1)) JDWN=IJ
C
      TY(IJYP(IJ))=KY(JDWN)/(DY*COEFF*MU(JDWN))
      TYRHO(IJYP(IJ))=RHON(JDWN)
C
 3020 CONTINUE
C
C-------------------------------------------------------
C
C       DEFINE DIFFERENCE COEFICIENTS
C
C-------------------------------------------------------
C
      DO 3030 IJ=1,NA
C
      Q(IJ)=0.D0
      B(IJ)=0.D0
      D(IJ)=0.D0
      E(IJ)=0.D0
```

```
      F(IJ)=0.D0
 3030 H(IJ)=0.D0
C
      DO 3090 IJ=1,NA
C
      IJM1=IJ-NX
      IM1J=IJ-1
      IP1J=IJ+1
      IJP1=IJ+NX
C
      IF(ISPEC(IJ).EQ.0) GO TO 3050
      IF(INOUT(ISPEC(IJ)).NE.-1) GO TO 3040
C
      E(IJ)=1.D0
      Q(IJ)=PSPEC(ISPEC(IJ))
C
      GO TO 3090
C
 3040 Q(IJ)=-QIN*RHO(IJ)
C
 3050 Q(IJ)=Q(IJ)+VB(IJ)*PHI(IJ)*(RHONP1(IJ)-RHON(IJ))/DT
C
      IF(MOD1(IJ).EQ.0) GO TO 3060
C
      F(IJ)=AX(IJ)*TX(IJXP(IJ))*TXRHO(IJXP(IJ))
      E(IJ)=E(IJ)-F(IJ)
C
      G=GRAV*(RHO(IJ)*HGT(IJ)-RHO(IP1J)*HGT(IP1J))
C
      Q(IJ)=Q(IJ)-F(IJ)*G
C
 3060 IF(IJ.GT.NAMNX) GO TO 3070
C
      H(IJ)=AY(IJ)*TY(IJYP(IJ))*TYRHO(IJYP(IJ))
      E(IJ)=E(IJ)-H(IJ)
```

```
C
      G=GRAV*(RHO(IJ)*HGT(IJ)-RHO(IJP1)*HGT(IJP1))
C
      Q(IJ)=Q(IJ)-H(IJ)*G
C
 3070  IF(MOD1(IJ).EQ.1) GO TO 3080
C
      D(IJ)=AX(IJ)*TX(IJXM(IJ))*TXRHO(IJXM(IJ))
      E(IJ)=E(IJ)-D(IJ)
C
      G=GRAV*(RHO(IM1J)*HGT(IM1J)-RHO(IJ)*HGT(IJ))
C
      Q(IJ)=Q(IJ)-D(IJ)*G
C
 3080  IF(IJ.LE.NX) GO TO 3090
C
      B(IJ)=AY(IJ)*TY(IJYM(IJ))*TYRHO(IJYM(IJ))
      E(IJ)=E(IJ)-B(IJ)
C
      G=GRAV*(RHO(IJM1)*HGT(IJM1)-RHO(IJ)*HGT(IJ))
C
      Q(IJ)=Q(IJ)-B(IJ)*G
C
 3090  CONTINUE
C
C-------------------------------------------------------
C
C       SOLVE FOR PRESSURE
C
C-------------------------------------------------------
C
      CALL SOLN (PN)
C
C-------------------------------------------------------
C
```

```
C       CALCULATE VELOCITIES
C
C-------------------------------------------------------------
C
      DO 3110 IJ=1,NA
C
      IP1J=IJ+1
      IJP1=IJ+NX
C
      IF(MOD1(IJ).EQ.0) GO TO 3100
C
       UX(IJXP(IJ))=TX(IJXP(IJ))*((PN(IJ)-PN(IP1J))
     1 +GRAV*(RHO(IJ)*HGT(IJ)-RHO(IP1J)*HGT(IP1J)))
C
      IF(DABS(UX(IJXP(IJ))).LE.SMALL) UX(IJXP(IJ))=TINY
C
 3100  IF(IJ.GT.NAMNX) GO TO 3110
C
      UY(IJYP(IJ))=TY(IJYP(IJ))*((PN(IJ)-PN(IJP1))
     1 +GRAV*(RHO(IJ)*HGT(IJ)-RHO(IJP1)*HGT(IJP1)))
C
      IF(DABS(UY(IJYP(IJ))).LE.SMALL) UY(IJYP(IJ))=TINY
C
 3110  CONTINUE
C
      DO 3120 IJ=1,NA
C
      IF(MOD1(IJ).EQ.1) UX(IJXM(IJ))=-UX(IJXP(IJ))
      IF(MOD1(IJ).EQ.0) UX(IJXP(IJ))=-UX(IJXM(IJ))
      IF(IJ.LE.NX) UY(IJYM(IJ))=-UY(IJYP(IJ))
      IF(IJ.GT.NAMNX) UY(IJYP(IJ))=-UY(IJYM(IJ))
C
 3120  CONTINUE
C
C-------------------------------------------------------------
```

```
C
C       MAGNITUDES AND DIRECTIONS OF VELOCITIES
C
C-------------------------------------------------------------
C
      DO 3130 IJ=1,NA
C
       UXIJ(IJ)=.5D0*(UX(IJXP(IJ))+UX(IJXM(IJ)))
      UYIJ(IJ)=.5D0*(UY(IJYP(IJ))+UY(IJYM(IJ)))
C
      IF(DABS(UXIJ(IJ)).LT.SMALL) UXIJ(IJ)=TINY
      IF(DABS(UYIJ(IJ)).LT.SMALL) UYIJ(IJ)=TINY
C
      TIJ=DATAN(UYIJ(IJ)/UXIJ(IJ))
C
      COSIJ=DCOS(TIJ)
      SINIJ=DSIN(TIJ)
C
      THETA(IJ)=TIJ
      COS2(IJ)=COSIJ*COSIJ
      SIN2(IJ)=SINIJ*SINIJ
      COSIN(IJ)=COSIJ*SINIJ
C
      U(IJ)=DSQRT(UXIJ(IJ)*UXIJ(IJ)+UYIJ(IJ)*UYIJ(IJ))
C
 3130  CONTINUE
C
C-------------------------------------------------------------
C
C       DEFINE DIFFUSION COEFFICIENTS
C
C-------------------------------------------------------------
C
      D1=D0/FRF
      D2=SIGMA*DPAR
```

```
C
      DO 3150 IJ=1,NA
C
      IP1J=IJ+1
      IM1J=IJ-1
      IJP1=IJ+NX
      IJM1=IJ-NX
C
      IP1JP1=IJP1+1
      IM1JP1=IJP1-1
      IP1JM1=IP1J-NX
C
      IF(MOD1(IJ).EQ.0) GO TO 3140
C
      IDWN=IJ
      IF(CNHLF(IJ).GT.CNHLF(IP1J)) IDWN=IP1J
C
      UDWN=U(IDWN)
C
      DXX(IJXP(IJ))=D1+D2*(ALFAL*COS2(IDWN)
     1 +ALFAT*SIN2(IDWN))*UDWN
C
      CRSX(IJXP(IJ))=0.D0
C
      IF(IJ.GT.NAMNX) GO TO 3140
      IF(IJ.LE.NX) GO TO 3140
C
      DXYDWN=
     1 D2*(ALFAL-ALFAT)*COSIN(IDWN)*UDWN
C
      CRSX(IJXP(IJ))=.25D0*DXYDWN*
     1 (CNHLF(IJP1)-CNHLF(IJM1)+CNHLF(IP1JP1)-CNHLF(IP1JM1))/DY
C
 3140 IF(IJ.GT.NAMNX) GO TO 3150
C
```

```
      JDWN=IJ
       IF(CNHLF(IJ).GT.CNHLF(IJP1)) JDWN=IJP1
C
      UDWN=U(JDWN)
C
      DYY(IJYP(IJ))=D1+D2*(ALFAL*SIN2(JDWN)
     1 +ALFAT*COS2(JDWN))*UDWN
C
      CRSY(IJYP(IJ))=0.D0
C
      IF(MOD1(IJ).EQ.0) GO TO 3150
      IF(MOD1(IJ).EQ.1) GO TO 3150
C
      DYXDWN=
     1 D2*(ALFAL-ALFAT)*COSIN(JDWN)*UDWN
C
      CRSY(IJYP(IJ))=.25D0*DYXDWN*
     1 (CNHLF(IP1J)-CNHLF(IM1J)+CNHLF(IP1JP1)-CNHLF(IM1JP1))/DX
C
 3150  CONTINUE
C
      DO 3160 IJ=1,NA
C
      IF(MOD1(IJ).EQ.0) DXX(IJXP(IJ))=DXX(IJXM(IJ))
      IF(MOD1(IJ).EQ.1) DXX(IJXM(IJ))=DXX(IJXP(IJ))
      IF(IJ.GT.NAMNX) DYY(IJYP(IJ))=DYY(IJYM(IJ))
      IF(IJ.LE.NX) DYY(IJYM(IJ))=DYY(IJYP(IJ))
C
      DXXIJ(IJ)=.5D0*(DXX(IJXP(IJ))+DXX(IJXM(IJ)))
     DYYIJ(IJ)=.5D0*(DYY(IJYP(IJ))+DYY(IJYM(IJ)))
C
      IF(MOD1(IJ).EQ.0) CRSX(IJXP(IJ))=CRSX(IJXM(IJ))
      IF(MOD1(IJ).EQ.1) CRSX(IJXM(IJ))=CRSX(IJXP(IJ))
      IF(IJ.GT.NAMNX) CRSY(IJYP(IJ))=CRSY(IJYM(IJ))
      IF(IJ.LE.NX) CRSY(IJYM(IJ))=CRSY(IJYP(IJ))
```

```
C
 3160  CONTINUE
C
C-----------------------------------------------------------
C
C       CELL NUMBER
C
C-----------------------------------------------------------
C
      XNCMAX=0.D0
      YNCMAX=0.D0
      XNCMIN=BIG
      YNCMIN=BIG
C
      DO 3170 IJ=1,NA
C
      XNC(IJ)=0.D0
      YNC(IJ)=0.D0
C
      IF(DXXIJ(IJ).GT.TINY)
     1 XNC(IJ)=DX*UXIJ(IJ)/DXXIJ(IJ)
      IF(DYYIJ(IJ).GT.TINY)
     1 YNC(IJ)=DY*UYIJ(IJ)/DYYIJ(IJ)
C
      IF(XNC(IJ).GT.XNCMAX) XNCMAX=XNC(IJ)
      IF(YNC(IJ).GT.YNCMAX) YNCMAX=YNC(IJ)
      IF(XNC(IJ).LT.XNCMIN) XNCMIN=XNC(IJ)
      IF(YNC(IJ).LT.YNCMIN) YNCMIN=YNC(IJ)
C
 3170  CONTINUE
C
C-----------------------------------------------------------
C
C       SOLVE CONVECTIVE-DIFFUSION EQUATION
C
```

```
C-----------------------------------------------------
C
      DO 4000 IJ=1,NA
C
      R1=U(IJ)*DT/(PHI(IJ)*DX)
      R2=U(IJ)*DT/(PHI(IJ)*DY)
C
      W1(IJ)=(COS2(IJ)+.5D0*R1*R1)/3.D0
      W2(IJ)=(SIN2(IJ)+.5D0*R2*R2)/3.D0
C
      W1(IJ)=0.D0
      W2(IJ)=0.D0
C
 4000  CONTINUE
C
      DO 4010 IJ=1,NA
C
 4010  ADS(IJ)=VB(IJ)*NSPH(IJ)*BETA(IJ)*RSTHLF(IJ)*RSTHLF(IJ)
C
C-----------------------------------------------------
C
C     DEFINE DIFFERENCE COEFFICIENTS
C
C-----------------------------------------------------
C
      DO 4020 IJ=1,NA
C
      Q(IJ)=0.D0
      B(IJ)=0.D0
      D(IJ)=0.D0
      F(IJ)=0.D0
      H(IJ)=0.D0
      E(IJ)=0.D0
C
 4020  CONTINUE
```

```
C
C-----------------------------------------------------
C
C     DFS : DIFFUSIVE
C     CNV : CONVECTIVE
C     WGT : NUMERICAL
C     ADS : ADSORPTIVE
C
C-----------------------------------------------------
C
      DO 4080 IJ=1,NA
C
      IM1J=IJ-1
      IP1J=IJ+1
      IJM1=IJ-NX
      IJP1=IJ+NX
C
      CNIJ=CN(IJ)
      PHIIJ=PHI(IJ)
C
      DFSXP=.5D0*AX(IJ)*(DXX(IJXP(IJ)))/DX
      DFSXM=.5D0*AX(IJ)*(DXX(IJXM(IJ)))/DX
      DFSYP=.5D0*AY(IJ)*(DYY(IJYP(IJ)))/DY
      DFSYM=.5D0*AY(IJ)*(DYY(IJYM(IJ)))/DY
C
      CNVXP=.25D0*AX(IJ)*UX(IJXP(IJ))
      CNVXM=.25D0*AX(IJ)*UX(IJXM(IJ))
      CNVYP=.25D0*AY(IJ)*UY(IJYP(IJ))
      CNVYM=.25D0*AY(IJ)*UY(IJYM(IJ))
C
      WGTX=.5D0*W1(IJ)*VB(IJ)/DT
      WGTY=.5D0*W2(IJ)*VB(IJ)/DT
C
      IF(ISPEC(IJ).EQ.0) GO TO 4040
      IF(INOUT(ISPEC(IJ)).NE.1) GO TO 4030
```

```
C
      E(IJ)=E(IJ)+.5D0*QIN*ALFA/(1.D0-ALFA)
      Q(IJ)=Q(IJ)+.5D0*QIN*(CSPEC(ISPEC(IJ))+CNIJ)
     1 +.5D0*QIN*CSPEC(ISPEC(IJ))*ALFA/(1.D0-ALFA)
C
      GO TO 4040
C
 4030 QOUT=AX(IJ)*UX(IJXM(IJ))+AY(IJ)*(UY(IJYM(IJ))-UY(IJYP(IJ)))
     1 -VB(IJ)*PHI(IJ)*(RHONP1(IJ)-RHON(IJ))/DT
      E(IJ)=E(IJ)+.5D0*QOUT
      Q(IJ)=Q(IJ)-.5D0*QOUT*CNIJ
C
C
 4040 E(IJ)=E(IJ)+VB(IJ)*PHIIJ/DT+.5D0*ADS(IJ)
      Q(IJ)=Q(IJ)+VB(IJ)*CNIJ*PHIIJ/DT-ADS(IJ)*(.5D0*CNIJ-CST)
C
      IF(MOD1(IJ).EQ.0) GO TO 4050
C
      CNIP1=CN(IP1J)
      PHIIP1=PHI(IP1J)
C
      F(IJ)=-DFSXP+CNVXP+PHIIP1*WGTX
      E(IJ)=E(IJ)+DFSXP+CNVXP-PHIIJ*WGTX
C
      Q(IJ)=Q(IJ)+DFSXP*(CNIP1-CNIJ)-CNVXP*(CNIP1+CNIJ)
     1 +WGTX*(PHIIP1*CNIP1-PHIIJ*CNIJ)+AX(IJ)*CRSX(IJXP(IJ))
C
 4050 IF(MOD1(IJ).EQ.1) GO TO 4060
C
      CNIM1=CN(IM1J)
      PHIIM1=PHI(IM1J)
C
      D(IJ)=-DFSXM-CNVXM+PHIIM1*WGTX
      E(IJ)=E(IJ)+DFSXM-CNVXM-PHIIJ*WGTX
C
```

```
      Q(IJ)=Q(IJ)+DFSXM*(CNIM1-CNIJ)+CNVXM*(CNIM1+CNIJ)
     1 +WGTX*(PHIIM1*CNIM1-PHIIJ*CNIJ)-AX(IJ)*CRSX(IJXM(IJ))
C
 4060 IF(IJ.GT.NAMNX) GO TO 4070
C
      CNJP1=CN(IJP1)
      PHIJP1=PHI(IJP1)
C
      H(IJ)=-DFSYP+CNVYP+PHIJP1*WGTY
      E(IJ)=E(IJ)+DFSYP+CNVYP-PHIIJ*WGTY
C
      Q(IJ)=Q(IJ)+DFSYP*(CNJP1-CNIJ)-CNVYP*(CNJP1+CNIJ)
     1 +WGTY*(PHIJP1*CNJP1-PHIIJ*CNIJ)+AY(IJ)*CRSY(IJYP(IJ))
C
 4070  IF(IJ.LE.NX) GO TO 4080
C
      CNJM1=CN(IJM1)
      PHIJM1=PHI(IJM1)
C
      B(IJ)=-DFSYM-CNVYM+PHIJM1*WGTY
      E(IJ)=E(IJ)+DFSYM-CNVYM-PHIIJ*WGTY
C
      Q(IJ)=Q(IJ)+DFSYM*(CNJM1-CNIJ)+CNVYM*(CNJM1+CNIJ)
     1 +WGTY*(PHIJM1*CNJM1-PHIIJ*CNIJ)-AY(IJ)*CRSY(IJYM(IJ))
C
 4080  CONTINUE
C
C-------------------------------------------------------
C
C     SOLVE FOR CONCENTRATION
C
C-------------------------------------------------------
C
      CALL SOLN (CNP1)
C
```

```
C-----------------------------------------------------------
C
C       CONVERGENCE CRITERION
C
C-----------------------------------------------------------
C
      K=K+1
C
      DCMAX=0.D0
C
      DO 2500 IJ=1,NA
C
      DCMX=DABS(CNP1(IJ)-CM(IJ))
      IF (DCMX.GT.DCMAX) DCMAX=DCMX
C
 2500  CONTINUE
C
      IF(DCMAX.GT.TOL.AND.K.LT.MAXIT) GO TO 2000
C
C-----------------------------------------------------------
C
C       DIFFERENTIAL MASS BALANCE CHECK
C
C-----------------------------------------------------------
C
      SNP1=0.D0
      QSOUT=0.D0
      QBOUT=0.D0
      QSIN=0.D0
      DFSIN=0.D0
      QADS=0.D0
C
C
      DO 5040 IJ=1,NA
C
```

```
      IJN=IJ+NA*(N-1)
      IJNP1=IJ+NA*N
C
      SAT(IJ)=PHINP1(IJ)/PHIMTX(IJ)
C
      SNP1=SNP1+PHINP1(IJ)*VB(IJ)*CNP1(IJ)
C
      QADS=QADS+NSPH(IJ)*VB(IJ)*
     1 (DT*BETA(IJ)*(CNHLF(IJ)-CST)
     2 +CNHLF(IJ)*(RST(IJNP1)-RST(IJN)))*RSTHLF(IJ)*RSTHLF(IJ)
C
 5040 CONTINUE
C
      DO 5041 IJ=1,NA
C
      IF(ISPEC(IJ).EQ.0) GO TO 5041
C
      IF(INOUT(ISPEC(IJ)).NE.1)GO TO 5031
C
      QSIN=QSIN+.5D0*QIN*(CSPEC(ISPEC(IJ))+CN(IJ))
      DFSIN=DFSIN+.5D0*QIN*(CSPEC(ISPEC(IJ))-CNP1(IJ))
     1 *ALFA/(1.D0-ALFA)
C
 5031 IF(INOUT(ISPEC(IJ)).NE.-1) GO TO 5041
C
      QOUT=AX(IJ)*UX(IJXM(IJ))+AY(IJ)*(UY(IJYM(IJ))-UY(IJYP(IJ)))
     1 -VB(IJ)*PHI(IJ)*(RHONP1(IJ)-RHON(IJ))/DT
      QSOUT=QSOUT+QOUT*CNHLF(IJ)
      QBOUT=QBOUT+QOUT*(1.D0-CNHLF(IJ))
C
      CEFFL=1.D0-CNHLF(IJ)
C
 5041 CONTINUE
C
      DMASB=(SNP1-SN+QADS+QSOUT*DT)/(DT*(QSIN+DFSIN))
```

```
C
C-------------------------------------------------------
C
C       CUMULATIVE MASS BALANCE CHECK
C
C-------------------------------------------------------
C
      QSOCM=QSOCM+QSOUT*DT
      QSICM=QSICM+QSIN*DT
      DFSICM=DFSICM+DFSIN*DT
      QINCM=QINCM+QINSUM*DT
      ADSCM=ADSCM+QADS
C
      PVINJ=QINCM/BIT
      BITREC=BITREC+QBOUT*DT/BIT
      SOLREC=SOLREC+QSOUT*DT/BIT
C
      CMASB=(SNP1-S0+ADSCM+QSOCM)/(QSICM+DFSICM)
C
C-------------------------------------------------------
C
C       UPDATE FOR NEW TIME INTERVAL
C
C-------------------------------------------------------
C
      DO 5050 IJ=1,NA
C
      CN(IJ)=CNP1(IJ)
      FN(IJ)=FNP1(IJ)
C
      IF(ISPEC(IJ).EQ.0) GO TO 5050
C
      IF(INOUT(ISPEC(IJ)).EQ.1) PIN=PN(IJ)
C
 5050 CONTINUE
```

```
C
C-------------------------------------------------------
C
C       OUTPUT
C
C-------------------------------------------------------
C
      WRITE(4,40) PVINJ,CEFFL,BITREC,SOLREC,QOUT
C
      WRITE(6,1)
      WRITE(6,21)
      WRITE(6,22) PVINJ,BITREC
      WRITE(6,23) TIME
      WRITE(6,24) QIN,QOUT
      WRITE(6,25) PIN
      WRITE(6,26) POUT
      WRITE(6,27) XNCMAX,XNCMIN,YNCMAX,YNCMIN
      WRITE(6,28) DMASB
      WRITE(6,29) CMASB
      WRITE(6,30) K
C
      WRITE(6,19)
      CALL OUTPT2 (2,6,CNP1)
C
      WRITE(6,20)
      CALL OUTPT2 (2,6,SAT)
C
      WRITE(6,39)
      READ(5,14)IOUT
C
      IF(IOUT.EQ.0) GO TO 5000
C
C-------------------------------------------------------
C
C     OUTPUT TO PLOT DATA FILE
```

```
C
C-------------------------------------------------
C
      WRITE(3,40) PVINJ
      CALL OUTPT1(3,CNP1)
      CALL OUTPT1(3,PN)
      CALL OUTPT1(3,SAT)
C
      WRITE(2,1)
      WRITE(2,21)
      WRITE(2,22) PVINJ,BITREC
      WRITE(2,23) TIME
      WRITE(2,24) QIN
      WRITE(2,25) PIN
      WRITE(2,26) POUT
      WRITE(2,27) XNCMAX,XNCMIN,YNCMAX,YNCMIN
      WRITE(2,28) DMASB
      WRITE(2,29) CMASB
      WRITE(2,30) K
C
      WRITE(2,19)
      CALL OUTPT2 (2,2,CNP1)
C
      WRITE(2,20)
      CALL OUTPT2 (2,2,SAT)
C
      WRITE(2,1)
C
      WRITE(2,31)
      CALL OUTPT2 (1,2,PN)
C
      WRITE(2,1)
      WRITE(2,32)
      CALL OUTPT2 (1,2,UXIJ)
C
```

```
      WRITE(2,33)
      CALL OUTPT2 (1,2,UYIJ)
C
      WRITE(2,1)
      WRITE(2,34)
      CALL OUTPT2 (1,2,DXXIJ)
C
      WRITE(2,35)
      CALL OUTPT2 (1,2,DYYIJ)
C
      WRITE(2,1)
      WRITE(2,36)
      CALL OUTPT2 (1,2,XNC)
C
      WRITE(2,37)
      CALL OUTPT2 (1,2,YNC)
C
C
5000  CONTINUE
C
      GO TO 1000
C
C*****************************************************************
C
9999  WRITE(6,1)
      WRITE(2,1)
C
      WRITE(3,41)
      WRITE(4,41)
C
      STOP
      END
C
C
C
```

```
C
      SUBROUTINE D4MAP(NX,NY,NZ)
C
      IMPLICIT REAL*8(A-H,O-Z)
C
C&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&
&&&&&&&&&&
C
C     SUBROUTINE 'D4MAP' GENERATES THE ALTERNATE DIAGONAL
C     NUMBERING SEQUENCE .
C
C&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&
&&&&&&&&&&
C
CCCCCCC OOOOOOO MMMMMMM MMMMMMM OOOOOOO NNNNNNN
C
      COMMON /D4MP/ D4,ID4
      INTEGER D4(500),ID4(500)
C
CCCCCCC OOOOOOO MMMMMMM MMMMMMM OOOOOOO NNNNNNN
C
C-------------------------------------------------------
C
C     D4(IJK) IS A POINTER ARRAY WHICH MAPS
C     NATURAL ORDERING INDEX TO ITS CORRESPONDING
C     D4 VALUE
C
C     ID4 IS THE INVERSE MAPPING ARRAY :
C     ID4(D4(IJK))=IJK
C
C-------------------------------------------------------
C
      M=NX+NY+NZ
      MEVEN=0
      IF(MOD(M,2).EQ.0)MEVEN=1
```

```
      MLAST=M
      IF(MEVEN.EQ.1)MLAST=M-1
      NFLAG=0
      NPLANE=3
      NUM=0
10    K=NPLANE-2
      IF(K.GE.NZ)K=NZ
20    I=0
      IF(K.LT.1)GO TO 40
30    I=I+1
      J=NPLANE-I-K
      IF(J.GT.NY)GO TO 30
      IF(I.GT.NX)GO TO 35
      IJ=I+NX*(J-1)+NX*NY*(K-1)
      NUM=NUM+1
      D4(IJ)=NUM
      ID4(NUM)=IJ
      IF(J.EQ.1.AND.K.EQ.1)GO TO 40
      IF(J.NE.1)GO TO 30
35    K=K-1
      GO TO 20
40    IF(NPLANE.NE.MLAST)GO TO 50
      NPLANE=2
      MLAST=M-1
      IF(MEVEN.EQ.1)MLAST=M
      IF(NFLAG.EQ.1)GO TO 60
      NFLAG=1
50    NPLANE=NPLANE+2
      GO TO 10
60    RETURN
      END
C
C
C
C
```

```
C
C
C
C
C
      SUBROUTINE INPUT1 (IDEV,NROW,MROW,X)
C
      IMPLICIT REAL*8 (A-H,O-Z)
C
C&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&
&&&&&&&&&&
C
C     SUBROUTINE 'INPUT1' READS A ONE-DIMENSIONAL DOUBLE
PRECISION
C     ARRAY OF EQUIVELANT DIMENSION (NROW,MROW)
C     WHICH IS PARTITIONED TO NI ELEMENTS PER LINE FROM
C     DEVICE (IDEV)
C
C&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&
&&&&&&&&&&
C
CCCCCCC OOOOOOO MMMMMMMM MMMMMMMM OOOOOOO NNNNNNN
C
      COMMON /IOPAR/ NI,NJ,NIO,NJO,MI,MJ
C
CCCCCCC OOOOOOO MMMMMMMM MMMMMMMM OOOOOOO NNNNNNN
C
      DIMENSION X(500)
C
C---------------------- FORMAT ----------------------------
C
100   FORMAT(15G16.6)
C
C-------------------------------------------------------------
C
```

```
      MMI=NROW/NI
      IF(MOD(NROW,NI).NE.0)MMI=MMI+1
C
      DO 10 J=1,MROW
C
      DO 10 KI=1,MMI
C
      ILO=1+NI*(KI-1)
      IHI=NI+NI*(KI-1)
C
      IF(IHI.GT.NROW) IHI=NROW
C
      IJLO=ILO+NROW*(J-1)
      IJHI=IHI+NROW*(J-1)
C
10    READ(IDEV,100)(X(IJ),IJ=IJLO,IJHI)
C
      RETURN
      END
C
C
      SUBROUTINE INPUT2 (IDEV,NROW,MROW,IX)
C
C&&&
```

```
C
      COMMON /IOPAR/ NI,NJ,NIO,NJO,MI,MJ
C
CCCCCCC OOOOOOO MMMMMMM MMMMMMM OOOOOOO NNNNNNN
C
      DIMENSION IX(500)
C
C-------------------------------------------------------
C
100   FORMAT(15I4)
C
C-------------------------------------------------------
C
      MMI=NROW/NI
      IF(MOD(NROW,NI).NE.0)MMI=MMI+1
C
      DO 10 J=1,MROW
C
      DO 10 KI=1,MMI
C
      ILO=1+NI*(KI-1)
      IHI=NI+NI*(KI-1)
C
      IF(IHI.GT.NROW) IHI=NROW
C
      IJLO=ILO+NROW*(J-1)
      IJHI=IHI+NROW*(J-1)
C
10    READ(IDEV,100)(IX(IJ),IJ=IJLO,IJHI)
C
      RETURN
      END
C
C
C
```

```
C
      SUBROUTINE OUTPT1 (IDEV,X8)
C
      REAL*8 X8(500)
      DIMENSION X4(500)
C
C&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&
&&&&&&&&&&
C
C     SUBROUTINE 'OUTPT1' WRITE A ONE-DIMENSIONAL SINGLE
PRECISION
C     ARRAY OF EQUIVELANT DIMENSION (NROW,MROW)
C     WHICH IS PARTITIONED TO NI ELEMENTS PER LINE ON
C     DEVICE (IDEV)
C
C&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&
&&&&&&&&&&
C
CCCCCCC OOOOOOO MMMMMMM MMMMMMM OOOOOOO NNNNNNN
C
      COMMON /IOPAR/ NI,NJ,NIO,NJO,MI,MJ
      COMMON /NGRD/ NX,NY,NA,NAMNX,NA2,NA2P1,MOD1
C
      DIMENSION MOD1(500)
CCCCCCC OOOOOOO MMMMMMM MMMMMMM OOOOOOO NNNNNNN
C
C
C---------------------- FORMAT ---------------------------
C
100   FORMAT(15G9.3)
C
C-------------------------------------------------------
C
      DO 1 IJ=1,NA
C
```

```
     1    X4(IJ)=X8(IJ)
     C
          DO 10 J=1,NY
     C
          IJLO=1+NX*(J-1)
          IJHI=NX+NX*(J-1)
     C
     10    WRITE(IDEV,100)(X4(IJ),IJ=IJLO,IJHI)
     C
          RETURN
          END
     C
     C
     C
     C
          SUBROUTINE OUTPT2 (IFORM,IDEV,X)
     C
          IMPLICIT REAL*8 (A-H,O-Z)
     C
     C&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&
     &&&&&&&&&&
     C
     C    ARRAY OUTPUT ON DEVICE=IDEV
     C&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&
     &&&&&&&&&&
     C
     CCCCCCC OOOOOOO MMMMMMM MMMMMMM OOOOOOO NNNNNNN
     C
          COMMON /NGRD/ NX,NY,NA,NAMNX,NA2,NA2P1,MOD1
          COMMON /IOPAR/ NI,NJ,NIO,NJO,MI,MJ
     C
          DIMENSION MOD1(500)
     C
     CCCCCCC OOOOOOO MMMMMMM MMMMMMM OOOOOOO NNNNNNN
     C
```

```
      DIMENSION X(500)
C
C---------------------- FORMAT ----------------------------
C
100   FORMAT(/,4X,15I10)
101   FORMAT('    JN')
102   FORMAT(1X,I2,6X,15F10.3)
103   FORMAT(1X,I2,8X,15G10.3)
C
C-------------------------------------------------------
C
      WRITE(IDEV,100)(I,I=1,NX,NIO)
      WRITE(IDEV,101)
C
      DO 10 J=1,NY,NJO
C
      IJLO=1+NX*(J-1)
      IJHI=NX+NX*(J-1)
C
      IF(IFORM.EQ.2)
     1 WRITE(IDEV,102)J,(X(IJ),IJ=IJLO,IJHI,NIO)
      IF(IFORM.EQ.1)
     1 WRITE(IDEV,103)J,(X(IJ),IJ=IJLO,IJHI,NIO)
C
10    CONTINUE
C
      RETURN
      END
C
C
C
C
      SUBROUTINE SOLN(X)
C
      IMPLICIT REAL*8 (A-H,O-Z)
```

```
C
C&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&
&&&&&&&&&&
C
C     SUBROUTINE 'SOLN' EXECUTES THE SOLUTION TO :
C
C                  AX=Q
C
C     WHERE EACH ELEMENT OF X IS A SCALAR (N=1) .
C
C&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&&
&&&&&&&&&&
C
CCCCCCC OOOOOOO MMMMMMM MMMMMMM OOOOOOO NNNNNNN
C
      COMMON /COEF/ B,D,E,F,H,Q
      COMMON /D4MP/ D4,ID4
      COMMON /NGRD/ NX,NY,NA,NAMNX,NA2,NA2P1,MOD1
C
      DIMENSION B(500),D(500),E(500),F(500),H(500),Q(500)
      INTEGER D4(500),ID4(500)
      DIMENSION MOD1(500)
C
CCCCCCC OOOOOOO MMMMMMM MMMMMMM OOOOOOO NNNNNNN
C
      REAL*8 LL
      DIMENSION X(500),Y(500)
      DIMENSION RL(5000),LL(5000)
C
C-------------------------------------------------------
C
C     COUPLED WITH D4 ODERING , 'SOLN' USES LR DECOMPOSITION :
C
C        A=LR
C
```

```
C    AND DETERMINES AN INTERMEDIATE VECTOR Y
C    BY FORWARD SUBSTITUTION :
C
C      LY=Q
C
C    FOLLOWED BY A BACKWARD SUBSTITUTION FOR X :
C
C      RX=Y
C
C-----------------------------------------------------
C
     NA2P2=NA2P1+1
     NA2P3=NA2P2+1
C
C-----------------------------------------------------
C
C    DETERMINE LMAX
C
C-----------------------------------------------------
C
     LMAX=0
C
C
     DO 15 IJ=NA2P2,NA
C
     LMXD4=ID4(IJ)+2
C
     IF(LMXD4.LT.1) GO TO 15
     IF(LMXD4.GT.NA) GO TO 15
     IF((D4(LMXD4)-IJ).GT.LMAX) LMAX=D4(LMXD4)-IJ
C
15   CONTINUE
C
C
C
```

```
C-----------------------------------------------------
C
C     INITIALIZE RL*,LL*
C
C-----------------------------------------------------
C
      NRL=NA2*(LMAX+1)
      NLL=NA2*LMAX
C
      DO 20 I=1,NRL
20    RL(I)=0.D0
C
      DO 25 I=1,NLL
25    LL(I)=0.D0
C
C
C-----------------------------------------------------
C
C     EVALUATE R0*
C
C-----------------------------------------------------
C
      DO 30 IJ=NA2P2,NA
C
      IJN2P1=IJ-NA2P1
      IJD4=ID4(IJ)
C
C
      RL(IJN2P1)=E(IJD4)
C
      IF(MOD1(IJD4).NE.0)RL(IJN2P1)=RL(IJN2P1)-
     1  F(IJD4)*D(IJD4+1)/E(IJD4+1)
C
      IF(MOD1(IJD4).NE.1)RL(IJN2P1)=RL(IJN2P1)-
     1  D(IJD4)*F(IJD4-1)/E(IJD4-1)
```

```
C
      IF(IJD4.LE.NAMNX)RL(IJN2P1)=RL(IJN2P1)-
     1  H(IJD4)*B(IJD4+NX)/E(IJD4+NX)
C
      IF(IJD4.GT.NX)RL(IJN2P1)=RL(IJN2P1)-
     1  B(IJD4)*H(IJD4-NX)/E(IJD4-NX)
C
30    CONTINUE
C
C-------------------------------------------------------
C
C     EVALUATE RL*,LL*  ; L=1,LMAX
C
C-------------------------------------------------------
C
      DO 60 IJ=NA2P2,NA
C
      IJD4=ID4(IJ)
      NAMIJ=NA-IJ
      IJN2P1=IJ-NA2P1
C
C
C-------------------------
C     TEST (1)
C-------------------------
C
      LD4=IJD4+2
C
      IF(LD4.LT.1) GO TO 35
      IF(LD4.GT.NA) GO TO 35
C
      L=D4(LD4)-IJ
C
      IF(L.LT.1) GO TO 35
      IF(L.GT.LMAX) GO TO 35
```

```
      IF(L.GT.NAMIJ) GO TO 35
C
      IF(MOD1(IJD4).EQ.0) GO TO 35
C
      LIJR=IJN2P1+L*NA2
      LIJL=IJN2P1+(L-1)*NA2+L
      IJD4L=ID4(IJ+L)
C
      RL(LIJR)=-F(IJD4)*F(IJD4+1)/E(IJD4+1)
      LL(LIJL)=-D(IJD4L)*D(IJD4L-1)/E(IJD4L-1)
C
C-----------------------------
C     TEST (2)
C-----------------------------
C
35    LD4=IJD4+NX+1
C
      IF(LD4.LT.1) GO TO 45
      IF(LD4.GT.NA) GO TO 45
C
      L=D4(LD4)-IJ
C
      IF(L.LT.1) GO TO 45
      IF(L.GT.LMAX) GO TO 45
      IF(L.GT.NAMIJ) GO TO 45
C
      LIJR=IJN2P1+L*NA2
      LIJL=IJN2P1+(L-1)*NA2+L
      IJD4L=ID4(IJ+L)
C
      IF(MOD1(IJD4).EQ.0) GO TO 40
C
      RL(LIJR)=-F(IJD4)*H(IJD4+1)/E(IJD4+1)
      LL(LIJL)=-D(IJD4L)*B(IJD4L-1)/E(IJD4L-1)
C
```

```
40    IF(IJD4.GT.NAMNX) GO TO 45
C
      RL(LIJR)=RL(LIJR)-H(IJD4)*F(IJD4+NX)/E(IJD4+NX)
      LL(LIJL)=LL(LIJL)-B(IJD4L)*D(IJD4L-NX)/E(IJD4L-NX)
C
C-------------------------
C     TEST (3)
C-------------------------
C
45    LD4=IJD4+2*NX
C
      IF(LD4.LT.1) GO TO 50
      IF(LD4.GT.NA) GO TO 50
C
      L=D4(LD4)-IJ
C
      IF(L.LT.1) GO TO 50
      IF(L.GT.LMAX) GO TO 50
      IF(L.GT.NAMIJ) GO TO 50
C
      IF(IJD4.GT.NAMNX) GO TO 50
C
      LIJR=IJN2P1+L*NA2
      LIJL=IJN2P1+(L-1)*NA2+L
      IJD4L=ID4(IJ+L)
C
      RL(LIJR)=-H(IJD4)*H(IJD4+NX)/E(IJD4+NX)
      LL(LIJL)=-B(IJD4L)*B(IJD4L-NX)/E(IJD4L-NX)
C
C-------------------------
C     TEST (4)
C-------------------------
C
50    LD4=IJD4-NX+1
C
```

```
      IF(LD4.LT.1) GO TO 60
      IF(LD4.GT.NA) GO TO 60
C
      L=D4(LD4)-IJ
C
      IF(L.LT.1) GO TO 60
      IF(L.GT.LMAX) GO TO 60
      IF(L.GT.NAMIJ) GO TO 60
C
      LIJR=IJN2P1+L*NA2
      LIJL=IJN2P1+(L-1)*NA2+L
      IJD4L=ID4(IJ+L)
C
      IF(MOD1(IJD4).EQ.0) GO TO 55
C
      RL(LIJR)=-F(IJD4)*B(IJD4+1)/E(IJD4+1)
      LL(LIJL)=-D(IJD4L)*H(IJD4L-1)/E(IJD4L-1)
C
55    IF(IJD4.LE.NX) GO TO 60
C
      RL(LIJR)=RL(LIJR)-B(IJD4)*F(IJD4-NX)/E(IJD4-NX)
      LL(LIJL)=LL(LIJL)-H(IJD4L)*D(IJD4L+NX)/E(IJD4L+NX)
C
60    CONTINUE
      LMAXP1=LMAX+1
C
C-------------------------------------------------------
C
C     EVALUATE RL,LL (RECURSIVELY)
C
C-------------------------------------------------------
C
      DO 85 IJ=NA2P3,NA
C
      IJN2P1=IJ-NA2P1
```

```
      MMIN=0
      MMAX=LMAX
      IF((NA2P2+LMAX-IJ).GT.MMIN)MMIN=NA2P2+LMAX-IJ
      IF((NA-IJ).LT.LMAX)MMAX=NA-IJ
      MMAX1=MMAX+1
      MMIN1=MMIN+1
      LMXMMN=LMAX-MMIN
C
      DO 70  M1=MMIN1,LMAX
C
      M=M1-1
      L=LMAX-M
      LIJ=IJN2P1+(L-1)*NA2
      N0IJ=IJN2P1-L
C
      IF(M.EQ.MMIN) GO TO 70
C
      DO 65 N=1,M
C
      LN=L+N
      LNIJ=IJN2P1+(LN-1)*NA2
      NIJ=IJN2P1-LN+N*NA2
C
65    LL(LIJ)=LL(LIJ)-LL(LNIJ)*RL(NIJ)
C
70    LL(LIJ)=LL(LIJ)/RL(N0IJ)
C
      DO 80 M1=1,MMAX1
C
      M=M1-1
      MIJ=IJN2P1+M*NA2
C
      IF(M.EQ.LMAX) GO TO 80
C
      IF((LMAX-M).LT.LMXMMN) LMXMMN=LMAX-M
```

```
C
      DO 75 N=1,LMXMMN
C
      MN=M+N
      MNIJ=IJN2P1-N+MN*NA2
      NIJ=IJN2P1+(N-1)*NA2
C
75     RL(MIJ)=RL(MIJ)-LL(NIJ)*RL(MNIJ)
C
80    CONTINUE
C
85   CONTINUE
C
C-------------------------------------------------------
C
C    LY=Q     FORWARD SUBSTITUTION
C
C-------------------------------------------------------
C
    DO 90 IJ=1,NA
C
90   Y(IJ)=Q(ID4(IJ))
C
    DO 100 IJ=NA2P2,NA
C
    IJD4=ID4(IJ)
C
C
    IF(MOD1(IJD4).NE.1)Y(IJ)=Y(IJ)-
   1 D(IJD4)*Y(D4(IJD4-1))/E(IJD4-1)
C
    IF(MOD1(IJD4).NE.0)Y(IJ)=Y(IJ)-
   1 F(IJD4)*Y(D4(IJD4+1))/E(IJD4+1)
C
    IF(IJD4.GT.NX)Y(IJ)=Y(IJ)-
```

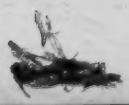
```
     1  B(IJD4)*Y(D4(IJD4-NX))/E(IJD4-NX)
C
      IF(IJD4.LE.NAMNX)Y(IJ)=Y(IJ)-
     1  H(IJD4)*Y(D4(IJD4+NX))/E(IJD4+NX)
C
      IF(IJ.EQ.NA2P2) GO TO 100
C
      MMAX=IJ-NA2P2
      IF(MMAX.GT.LMAX) MMAX=LMAX
C
      DO 95 L=1,MMAX
C
      LIJ=IJ-NA2P1+(L-1)*NA2
C
95     Y(IJ)=Y(IJ)-LL(LIJ)*Y(IJ-L)
C
100   CONTINUE
C
C-------------------------------------------------------
C
C     RX=Y      BACKWARD SUBSTITUTION
C
C-------------------------------------------------------
C
      DO 110 MIJ=1,NA2
C
      IJ=NA-MIJ+1
      IJD4=ID4(IJ)
C
      X(IJD4)=Y(IJ)
C
      IF(IJ.EQ.NA) GO TO 110
C
      MMAX=NA-IJ
      IF(MMAX.GT.LMAX) MMAX=LMAX
```

```
C
      DO 105 L=1,MMAX
C
      LIJ=IJ-NA2P1+L*NA2
C
105     X(IJD4)=X(IJD4)-RL(LIJ)*X(ID4(IJ+L))
C
110   X(IJD4)=X(IJD4)/RL(IJ-NA2P1)
C
      DO 115 MIJ=1,NA2P1
C
      IJ=NA2P2-MIJ
      IJD4=ID4(IJ)
C
C
      X(IJD4)=Y(IJ)
C
      IF(MOD1(IJD4).NE.1)X(IJD4)=X(IJD4)-
     1  D(IJD4)*X(IJD4-1)
C
      IF(MOD1(IJD4).NE.0)X(IJD4)=X(IJD4)-
     1  F(IJD4)*X(IJD4+1)
C
      IF(IJD4.GT.NX)X(IJD4)=X(IJD4)-
     1  B(IJD4)*X(IJD4-NX)
C
      IF(IJD4.LE.NAMNX)X(IJD4)=X(IJD4)-
     1  H(IJD4)*X(IJD4+NX)
C
115   X(IJD4)=X(IJD4)/E(IJD4)
C
      RETURN
      END
```

INPUT FILE - HOMOGENEOUS RUN (k_x=k_y = 19μm^2)

```
10,12,
60.,6.25,3.75,
11,13,2,1,
1.91D5,4.56,.5508
1.03,0.8665,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00
```

```
.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,
.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,
.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,
.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,
.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,
.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,
.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,.39,
5.0D-7,4.,3.5,.1,.5,.0157,
.03,.250,7.D-9,5.D-7,
1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,.25,
2,
0,0,0,0,0,0,0,0,0,0,0,
0,0,0,0,0,0,0,0,0,0,0,
0,0,0,0,0,0,0,0,0,0,0,
0,0,0,0,0,0,0,0,0,0,0,
1,0,0,0,0,0,0,0,0,0,0,
0,0,0,0,0,0,0,0,0,0,0,
0,0,0,0,0,0,0,0,0,0,2,
0,0,0,0,0,0,0,0,0,0,0,
0,0,0,0,0,0,0,0,0,0,0,
0,0,0,0,0,0,0,0,0,0,0,
0,0,0,0,0,0,0,0,0,0,0,
0,0,0,0,0,0,0,0,0,0,0,
0,0,0,0,0,0,0,0,0,0,0,
1,-1,
1.,0.,
20.,14.7,
```



```
0.0
7,1000
1.D25,1.D-15,1.D-12,1.D-4,1.D-4,
```

INPUT FILE - BOTTOM WATER RUN (k_{aw} = 24 μm^2; k_x=k_y = 100 μm^2)

```
10,12,
60.,6.25,3.75,
11,13,2,1,
1.91D5,4.56,.5508
1.03,0.8665,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,0.00,
100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,
100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,
100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,
100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,
100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,
100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,100.0,
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PARTIAL OUTPUT SHOWING GRID BLOCK SATURATIONS, PRESSURES AND CONCENTRATIONS FOR BOTTOM WATER RUN SIMULATION
($k_{aw} = 24\mu m^2$, $k_x = k_y = 100\mu m^2$)

LENGTH (cm) = 60.00
WIDTH (cm) = 6.250
THICK. (cm) = 3.750

OIL VISCOSITY (cp) = 0.1910E+06
SOL VISCOSITY (cp) = 4.560

OIL DENSITY (gm/cc) = 1.030
SOL DENSITY (gm/cc) = 0.8665

MOLECULAR DIFF COEF (cm**2/sec) = 0.5000E-06
FORMATION RESISTIVITY FACTOR = 4.000
PARTICLE DIA (GRAIN SIZE) (cm) = 0.1000
PACKING INHOMOGENEITY FACTOR = 3.500

INITIAL BITUMEN RADIUS (cm) = 0.3000E-01
CONSTANT SURFACE CONC. = 0.2500
SOLID DIFF COEF (cm**2/sec) = 0.7000E-08
MASS TRANSFER COEF (cm/sec) = 0.5000E-06

1 PERMEABILITY (KX Darcy)

JN	1	3	5	7	9	11
1	100.	100.	100.	100.	100.	100.
2	100.	100.	100.	100.	100.	100.
3	100.	100.	100.	100.	100.	100.
4	100.	100.	100.	100.	100.	100.
5	100.	100.	100.	100.	100.	100.
6	100.	100.	100.	100.	100.	100.
7	100.	100.	100.	100.	100.	100.
8	100.	100.	100.	100.	100.	100.
9	100.	100.	100.	100.	100.	100.
10	100.	100.	100.	100.	100.	100.
11	100.	100.	100.	100.	100.	100.
12	24.0	24.0	24.0	24.0	24.0	24.0
13	24.0	24.0	24.0	24.0	24.0	24.0

PERMEABILITY (KY Darcy)

JN	1	3	5	7	9	11

1	100.	100.	100.	100.	100.	100.
2	100.	100.	100.	100.	100.	100.
3	100.	100.	100.	100.	100.	100.
4	100.	100.	100.	100.	100.	100.
5	100.	100.	100.	100.	100.	100.
6	100.	100.	100.	100.	100.	100.
7	100.	100.	100.	100.	100.	100.
8	100.	100.	100.	100.	100.	100.
9	100.	100.	100.	100.	100.	100.
10	100.	100.	100.	100.	100.	100.
11	100.	100.	100.	100.	100.	100.
12	24.0	24.0	24.0	24.0	24.0	24.0
13	24.0	24.0	24.0	24.0	24.0	24.0

1 HEIGHT (cm)

N	1	3	5	7	9	11
1	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
2	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
3	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
4	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
5	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
6	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
7	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
8	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
9	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
10	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
11	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
12	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
13	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00

POROSITY

N	1	3	5	7	9	11
1	0.390	0.390	0.390	0.390	0.390	0.390
2	0.390	0.390	0.390	0.390	0.390	0.390
3	0.390	0.390	0.390	0.390	0.390	0.390
4	0.390	0.390	0.390	0.390	0.390	0.390
5	0.390	0.390	0.390	0.390	0.390	0.390
6	0.390	0.390	0.390	0.390	0.390	0.390
7	0.390	0.390	0.390	0.390	0.390	0.390
8	0.390	0.390	0.390	0.390	0.390	0.390
9	0.390	0.390	0.390	0.390	0.390	0.390
10	0.390	0.390	0.390	0.390	0.390	0.390
11	0.390	0.390	0.390	0.390	0.390	0.390
12	0.390	0.390	0.390	0.390	0.390	0.390

13	0.390	0.390	0.390	0.390	0.390	0.390

1

CONCENTRATION

JN	1	3	5	7	9	11
1	1.000	1.000	1.000	1.000	1.000	1.000
2	1.000	1.000	1.000	1.000	1.000	1.000
3	1.000	1.000	1.000	1.000	1.000	1.000
4	1.000	1.000	1.000	1.000	1.000	1.000
5	1.000	1.000	1.000	1.000	1.000	1.000
6	1.000	1.000	1.000	1.000	1.000	1.000
7	1.000	1.000	1.000	1.000	1.000	1.000
8	1.000	1.000	1.000	1.000	1.000	1.000
9	1.000	1.000	1.000	1.000	1.000	1.000
10	1.000	1.000	1.000	1.000	1.000	1.000
11	1.000	1.000	1.000	1.000	1.000	1.000
12	1.000	1.000	1.000	1.000	1.000	1.000
13	1.000	1.000	1.000	1.000	1.000	1.000

SATURATION

JN	1	3	5	7	9	11
1	0.250	0.250	0.250	0.250	0.250	0.250
2	0.250	0.250	0.250	0.250	0.250	0.250
3	0.250	0.250	0.250	0.250	0.250	0.250
4	0.250	0.250	0.250	0.250	0.250	0.250
5	0.250	0.250	0.250	0.250	0.250	0.250
6	0.250	0.250	0.250	0.250	0.250	0.250
7	0.250	0.250	0.250	0.250	0.250	0.250
8	0.250	0.250	0.250	0.250	0.250	0.250
9	0.250	0.250	0.250	0.250	0.250	0.250
10	0.250	0.250	0.250	0.250	0.250	0.250
11	0.250	0.250	0.250	0.250	0.250	0.250
12	1.000	1.000	1.000	1.000	1.000	1.000
13	1.000	1.000	1.000	1.000	1.000	1.000

ENTER : FLOW RATE - QIN (cc/sec)
?

ENTER : PORE VOL. INJECTED (dPV,NdPV)
?
1

P.V. SOL INJECTED = 0.761905E-01
P.V. BIT PRODUCED = 0.581341E-03

FLOW RATE (cc/sec) = 0.8300E-01

INLET PRES. (psi) = 21.9222
OUTLET PRES.(psi) = 14.7000

X-CELL NO. (MAX,MIN) = (68.6 ,0.183E-11)
Y-CELL NO. (MAX,MIN) = (10.1 ,-8.50)

DIFF. MASS BAL. = 1.00002
CUM. MASS BAL. = 1.00002

ITERATIONS K = 7

CONCENTRATION

JN	1	3	5	7	9	11
1	0.976	0.968	0.968	0.968	0.968	0.968
2	0.985	0.968	0.968	0.968	0.968	0.968
3	0.991	0.968	0.968	0.968	0.968	0.968
4	0.996	0.968	0.968	0.968	0.968	0.967
5	0.999	0.968	0.968	0.968	0.968	0.968
6	0.998	0.968	0.968	0.968	0.968	0.964
7	0.997	0.968	0.968	0.968	0.968	0.984
8	0.995	0.968	0.968	0.968	0.967	0.995
9	0.994	0.968	0.968	0.968	0.967	0.993
10	0.992	0.969	0.968	0.968	0.968	0.996
11	0.989	0.964	0.968	0.969	0.972	0.998
12	0.994	0.993	0.998	0.999	1.000	1.001
13	0.996	0.997	0.999	1.000	1.000	0.999

SATURATION

JN	1	3	5	7	9	11
1	0.228	0.228	0.228	0.228	0.228	0.228
2	0.228	0.228	0.228	0.228	0.228	0.228
3	0.228	0.228	0.228	0.228	0.228	0.228
4	0.228	0.228	0.228	0.228	0.228	0.228
5	0.228	0.228	0.228	0.228	0.228	0.228

6	0.228	0.228	0.228	0.228	0.228	0.227
7	0.228	0.228	0.228	0.228	0.228	0.228
8	0.228	0.228	0.228	0.228	0.228	0.228
9	0.228	0.228	0.228	0.228	0.228	0.228
10	0.228	0.228	0.228	0.228	0.228	0.228
11	0.228	0.227	0.228	0.228	0.228	0.228
12	1.000	1.000	1.000	1.000	1.000	1.000
13	1.000	1.000	1.000	1.000	1.000	1.000

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PRESSURE (psi)

JN	1	3	5	7	9	11
1	21.7	19.3	18.4	17.5	16.6	15.0
2	21.7	19.3	18.4	17.5	16.6	15.0
3	21.8	19.3	18.4	17.5	16.6	15.0
4	21.8	19.3	18.4	17.5	16.6	14.9
5	21.9	19.3	18.4	17.5	16.6	14.9
6	21.6	19.3	18.4	17.5	16.6	14.8
7	21.3	19.3	18.4	17.5	16.6	14.7
8	21.0	19.3	18.4	17.5	16.7	15.0
9	20.7	19.3	18.4	17.5	16.7	15.3
10	20.4	19.3	18.4	17.5	16.7	15.6
11	20.2	19.3	18.4	17.5	16.7	15.9
12	20.0	19.3	18.4	17.5	16.7	15.9
13	19.9	19.3	18.4	17.5	16.7	15.9

VISCOSITY (cp)

JN	1	3	5	7	9	11
1	4.98	4.98	4.98	4.98	4.98	4.98
2	4.98	4.98	4.98	4.98	4.98	4.98
3	4.98	4.98	4.98	4.98	4.98	4.98
4	4.98	4.98	4.98	4.98	4.98	4.98
5	4.98	4.98	4.98	4.98	4.98	4.98
6	4.98	4.98	4.98	4.98	4.98	4.98
7	4.98	4.98	4.98	4.98	4.98	4.98
8	4.98	4.98	4.98	4.98	4.98	4.98
9	4.98	4.98	4.98	4.98	4.98	4.98
10	4.98	4.98	4.98	4.98	4.98	4.98
11	4.98	4.98	4.98	4.98	4.98	4.98
12	4.98	4.98	4.98	4.98	4.98	4.98
13	4.98	4.98	4.98	4.98	4.98	4.98

KX (Darcy)

JN	1	3	5	7	9	11
1	0.617	0.616	0.616	0.616	0.616	0.616
2	0.618	0.616	0.616	0.616	0.616	0.616
3	0.618	0.616	0.616	0.616	0.616	0.616
4	0.618	0.616	0.616	0.616	0.616	0.616
5	0.619	0.616	0.616	0.616	0.616	0.616
6	0.619	0.616	0.616	0.616	0.616	0.616
7	0.618	0.616	0.616	0.616	0.616	0.618
8	0.618	0.616	0.616	0.616	0.616	0.618
9	0.618	0.616	0.616	0.616	0.616	0.618
10	0.618	0.616	0.616	0.616	0.616	0.618
11	0.618	0.616	0.616	0.616	0.617	0.619
12	24.0	24.0	24.0	24.0	24.0	24.0
13	24.0	24.0	24.0	24.0	24.0	24.0

KY (Darcy)

JN	1	3	5	7	9	11
1	0.617	0.616	0.616	0.616	0.616	0.616
2	0.618	0.616	0.616	0.616	0.616	0.616
3	0.618	0.616	0.616	0.616	0.616	0.616
4	0.618	0.616	0.616	0.616	0.616	0.616
5	0.619	0.616	0.616	0.616	0.616	0.616
6	0.619	0.616	0.616	0.616	0.616	0.616
7	0.618	0.616	0.616	0.616	0.616	0.618
8	0.618	0.616	0.616	0.616	0.616	0.618
9	0.618	0.616	0.616	0.616	0.616	0.618
10	0.618	0.616	0.616	0.616	0.616	0.618
11	0.618	0.616	0.616	0.616	0.617	0.619
12	24.0	24.0	24.0	24.0	24.0	24.0
13	24.0	24.0	24.0	24.0	24.0	24.0

PHI

JN	1	3	5	7	9	11
1	0.932E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01
2	0.932E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01
3	0.932E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01

4	0.932E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01
5	0.933E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01
6	0.932E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01
7	0.932E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01	0.932E-01
8	0.932E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01	0.932E-01
9	0.932E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01	0.932E-01
10	0.932E-01	0.931E-01	0.931E-01	0.931E-01	0.931E-01	0.932E-01
11	0.932E-01	0.931E-01	0.931E-01	0.931E-01	0.932E-01	0.932E-01
12	0.390	0.390	0.390	0.390	0.390	0.390
13	0.390	0.390	0.390	0.390	0.390	0.390

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UX (cm/sec)

JN	1	3	5	7	9	11
1	0.100E-14	0.858E-03	0.621E-03	0.612E-03	0.735E-03	0.100E-14
2	0.100E-14	0.856E-03	0.621E-03	0.612E-03	0.734E-03	0.100E-14
3	0.100E-14	0.849E-03	0.621E-03	0.612E-03	0.731E-03	0.100E-14
4	0.100E-14	0.837E-03	0.620E-03	0.612E-03	0.725E-03	0.100E-14
5	0.100E-14	0.820E-03	0.619E-03	0.611E-03	0.716E-03	0.100E-14
6	0.100E-14	0.796E-03	0.618E-03	0.611E-03	0.704E-03	0.100E-14
7	0.100E-14	0.767E-03	0.617E-03	0.610E-03	0.687E-03	0.100E-14
8	0.100E-14	0.734E-03	0.616E-03	0.609E-03	0.667E-03	0.100E-14
9	0.100E-14	0.699E-03	0.614E-03	0.609E-03	0.643E-03	0.100E-14
10	0.100E-14	0.662E-03	0.613E-03	0.608E-03	0.617E-03	0.100E-14
11	0.100E-14	0.624E-03	0.611E-03	0.607E-03	0.591E-03	0.100E-14
12	0.100E-14	0.228E-01	0.237E-01	0.236E-01	0.230E-01	0.100E-14
13	0.100E-14	0.228E-01	0.237E-01	0.236E-01	0.230E-01	0.100E-14

UY (cm/sec)

JN	1	3	5	7	9	11
1	0.100E-14	0.100E-14	0.100E-14	0.100E-14	0.100E-14	0.100E-14
2	-0.404E-03	0.270E-04	0.425E-06	-0.127E-05	-0.161E-04	0.255E-03
3	-0.816E-03	0.535E-04	0.824E-06	-0.252E-05	-0.320E-04	0.515E-03
4	-0.124E-02	0.790E-04	0.117E-05	-0.374E-05	-0.475E-04	0.784E-03
5	0.199E-02	0.103E-03	0.144E-05	-0.492E-05	-0.622E-04	0.107E-02
6	0.525E-02	0.124E-03	0.161E-05	-0.606E-05	-0.757E-04	0.137E-02
7	0.489E-02	0.143E-03	0.165E-05	-0.713E-05	-0.878E-04	-0.190E-02
8	0.459E-02	0.158E-03	0.156E-05	-0.813E-05	-0.976E-04	-0.519E-02
9	0.435E-02	0.169E-03	0.132E-05	-0.905E-05	-0.105E-03	-0.495E-02
10	0.416E-02	0.176E-03	0.908E-06	-0.989E-05	-0.109E-03	-0.477E-02
11	0.403E-02	0.178E-03	0.328E-06	-0.106E-04	-0.110E-03	-0.466E-02
12	0.264E-02	0.119E-03	-0.772E-08	-0.732E-05	-0.729E-04	-0.308E-02

13 0.100E-14 0.100E-14 0.100E-14 0.100E-14 0.100E-14 0.100E-14
1

DXX (cm**2/sec)

N	1	3	5	7	9	11
1	0.292E-03	0.133E-03	0.108E-03	0.109E-03	0.156E-03	0.201E-03
2	0.293E-03	0.133E-03	0.108E-03	0.109E-03	0.156E-03	0.201E-03
3	0.296E-03	0.132E-03	0.108E-03	0.109E-03	0.157E-03	0.204E-03
4	0.301E-03	0.131E-03	0.108E-03	0.109E-03	0.159E-03	0.444E-05
5	0.308E-03	0.129E-03	0.108E-03	0.108E-03	0.161E-03	0.213E-03
6	0.260E-03	0.126E-03	0.108E-03	0.108E-03	0.165E-03	0.767E-05
7	0.215E-03	0.122E-03	0.108E-03	0.108E-03	0.168E-03	0.228E-03
8	0.173E-03	0.119E-03	0.107E-03	0.107E-03	0.116E-03	0.182E-03
9	0.134E-03	0.115E-03	0.107E-03	0.107E-03	0.111E-03	0.138E-03
10	0.100E-03	0.111E-03	0.107E-03	0.107E-03	0.107E-03	0.979E-04
11	0.700E-04	0.105E-03	0.107E-03	0.107E-03	0.104E-03	0.614E-04
12	0.327E-02	0.363E-02	0.414E-02	0.414E-02	0.407E-02	0.170E-04
13	0.125E-06	0.363E-02	0.414E-02	0.414E-02	0.407E-02	0.125E-06

DYY (cm**2/sec)

N	1	3	5	7	9	11
1	0.125E-06	0.484E-05	0.354E-05	0.349E-05	0.417E-05	0.448E-04
2	0.355E-04	0.491E-05	0.354E-05	0.349E-05	0.419E-05	0.448E-04
3	0.107E-03	0.517E-05	0.354E-05	0.349E-05	0.430E-05	0.911E-04
4	0.180E-03	0.569E-05	0.353E-05	0.349E-05	0.451E-05	0.137E-03
5	0.569E-03	0.642E-05	0.353E-05	0.349E-05	0.481E-05	0.189E-03
6	0.888E-03	0.785E-05	0.352E-05	0.349E-05	0.519E-05	0.240E-03
7	0.830E-03	0.937E-05	0.351E-05	0.349E-05	0.581E-05	0.286E-03
8	0.783E-03	0.103E-04	0.350E-05	0.349E-05	0.639E-05	0.599E-03
9	0.745E-03	0.108E-04	0.350E-05	0.349E-05	0.656E-05	0.866E-03
10	0.717E-03	0.114E-04	0.350E-05	0.349E-05	0.666E-05	0.851E-03
11	0.705E-03	0.120E-04	0.349E-05	0.349E-05	0.679E-05	0.826E-03
12	0.584E-03	0.689E-04	0.670E-04	0.668E-04	0.666E-04	0.408E-03
13	0.463E-03	0.126E-03	0.131E-03	0.130E-03	0.126E-03	0.125E-06

1

CELL.NO.-X

1	3	5	7	9	11

JN						
1	0.206E-10	38.7	34.5	33.7	28.4	0.299E-10
2	0.205E-10	38.6	34.5	33.7	28.2	0.298E-10
3	0.203E-10	38.6	34.5	33.8	27.9	0.294E-10
4	0.199E-10	38.5	34.5	33.8	27.4	0.135E-08
5	0.195E-10	38.3	34.5	33.8	26.6	0.281E-10
6	0.231E-10	38.0	34.4	33.9	25.6	0.783E-09
7	0.279E-10	37.6	34.4	34.0	24.5	0.263E-10
8	0.347E-10	37.1	34.4	34.2	34.6	0.329E-10
9	0.446E-10	36.6	34.4	34.2	34.7	0.433E-10
10	0.599E-10	35.9	34.2	34.2	34.7	0.613E-10
11	0.858E-10	35.5	34.2	34.2	34.2	0.978E-10
12	0.183E-11	37.7	34.4	34.2	33.9	0.352E-09
13	0.480E-07	37.7	34.4	34.2	33.9	0.480E-07

CELL.NO.-Y

	1	3	5	7	9	11
JN						
1	0.417E-08	0.108E-09	0.147E-09	0.149E-09	0.125E-09	0.116E-10
2	-5.93	2.86	0.626E-01	-0.189	-2.00	2.97
3	-3.98	5.38	0.121	-0.375	-3.88	2.94
4	-3.59	7.23	0.172	-0.558	-5.48	2.97
5	1.83	8.35	0.212	-0.735	-6.73	2.95
6	3.08	8.26	0.238	-0.903	-7.61	2.97
7	3.07	7.95	0.245	-1.06	-7.87	-3.45
8	3.06	7.95	0.232	-1.21	-7.95	-4.51
9	3.04	8.14	0.196	-1.35	-8.32	-2.98
10	3.03	8.03	0.135	-1.47	-8.50	-2.92
11	2.98	7.74	0.491E-01	-1.58	-8.40	-2.94
12	2.36	0.902	-0.600E-04	-0.571E-01	-0.570	-3.93
13	0.113E-11	0.414E-11	0.399E-11	0.401E-11	0.412E-11	0.417E-08

1

* T.C.P. *

OUTPUT FOR BOTTOM WATER RUN (k_{aw} = 24μm^2; k_x=k_y = 100μm^2)

0.762E-010.782E-020.581E-030.738E-010.810E-01

0.152	0.157E-01	0.175E-02	0.147 0.810E-01
0.229	0.213E-01	0.334E-02	0.220 0.811E-01
0.305	0.287E-01	0.548E-02	0.292 0.811E-01
0.381	0.388E-01	0.838E-02	0.364 0.813E-01
0.457	0.489E-01	0.120E-01	0.435 0.812E-01
0.533	0.498E-01	0.157E-01	0.506 0.814E-01
0.610	0.483E-01	0.194E-01	0.577 0.813E-01
0.686	0.524E-01	0.233E-01	0.648 0.815E-01
0.762	0.591E-01	0.277E-01	0.718 0.814E-01
0.838	0.549E-01	0.318E-01	0.789 0.815E-01
0.914	0.601E-01	0.363E-01	0.859 0.816E-01
0.990	0.657E-01	0.412E-01	0.929 0.815E-01
1.07	0.656E-01	0.461E-01	0.999 0.816E-01
1.14	0.659E-01	0.511E-01	1.07 0.816E-01